Blueknight Energy Partners, L.P.
Form 10-K
March 08, 2018

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

FORM 10-K

x ANNUAL REPORT PURSUANT TO SECTION 13 or 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2017

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 (State or other jurisdiction of incorporation or organization)	20-8536826 (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, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer", "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):

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

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. 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, 2017, the aggregate market value of the registrant's common units held by non-affiliates of the registrant was approximately $191.6 million, based on $6.25 per common unit, the closing price of the common units as reported on the Nasdaq Global Market on such date.

As of March 1, 2018, there were 35,125,202 Series A Preferred Units and 40,310,272 common units outstanding.

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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 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: 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 liquid 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 representing 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.).

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.

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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) “Ergon” refers to Ergon, Inc., its affiliates and subsidiaries (other than our General Partner and us), (4) “Vitol” refers to Vitol Holding B.V., its affiliates and subsidiaries and (5) “Charlesbank” refers to Charlesbank Capital Partners, LLC, its affiliates and subsidiaries.

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 or assumptions 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 Investors - SEC Filings page at www.bkep.com and through the SEC’s Electronic Data Gathering and Retrieval System (“EDGAR”) at 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 27 states. We provide integrated terminalling, gathering and transportation services for companies engaged in the production, distribution and marketing of liquid asphalt and crude oil. We manage our operations through four operating segments: (i) asphalt terminalling services, (ii) crude oil terminalling services, (iii) crude oil pipeline services and (iv) crude oil trucking and producer field 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 owned by Blueknight Energy Holding GP, LLC. On October 5, 2016, Ergon purchased 100% of the outstanding voting stock of Blueknight GP Holding, L.L.C., which owns 100% of the capital stock of our General Partner, pursuant to a Membership Interest Purchase Agreement dated July 19, 2016, among CB-Blueknight, LLC (“CBB”), an indirect wholly-owned subsidiary of Charlesbank, Blueknight Energy Holding, Inc. (“BEHI”), an indirect wholly-owned subsidiary of Vitol, and Ergon Asphalt Holdings, LLC, a wholly-owned subsidiary of Ergon (the “Ergon Change of Control”). In conjunction with the Ergon Change of Control, Ergon contributed nine asphalt terminals plus $22.1 million in cash in return for total consideration of approximately $144.7 million, which consisted of the issuance of 18,312,968 Preferred Units in a private placement. We also repurchased 6,667,695 Preferred Units from each Vitol and Charlesbank in a private placement for an aggregate purchase price of approximately $95.3 million. Vitol and Charlesbank each retained 2,488,789 Preferred Units upon completion of these transactions. In addition, Ergon acquired an aggregate of $5.0 million of common units for cash in a private placement, pursuant to a Contribution Agreement between us, Blueknight Terminal Holding, L.L.C. and three indirect wholly-owned subsidiaries of Ergon.

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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 March 1, 2018:

Our Strengths and Strategies

Strategically placed assets. We own and operate a diversified portfolio of complementary midstream energy assets that includes approximately 10.3 million barrels of liquid asphalt storage located at 56 terminals in 26 states which we believe are well positioned to provide services in the market areas they serve throughout the continental United States. Our primary crude oil terminalling facilities are located within the Cushing Interchange in Cushing, Oklahoma, one of the largest crude oil

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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 655 miles of strategically positioned gathering and transportation pipelines in Oklahoma and Texas.

Growth opportunities. Ergon has indicated that it intends to use us as a growth vehicle to pursue the acquisition and expansion of midstream energy businesses and assets. We cannot say with any certainty whether or not Ergon will develop any projects or, if they do, which, if any, 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 customers of our asphalt terminalling services and with producers, marketers and refiners of crude oil.

Our relationship with Ergon. Ergon owns our General Partner and therefore controls our operations. Ergon is a privately held company formed in 1954 and is based in Jackson, Mississippi, with over 2,500 employees globally. Ergon and its subsidiaries are engaged in a wide range of operations that are categorized into six primary business segments: Refining & Marketing, Asphalt & Emulsions, Transportation & Terminalling, Oil & Gas, Real Estate and Corporate & Other. This relationship may provide us with additional capital sources for future growth as well as increased opportunities to provide terminalling, gathering and transportation services. While this relationship may benefit us, it may also be a source of potential conflicts. Ergon is not restricted from competing with us and may acquire, construct or dispose of additional assets in the future without any obligation to offer us the opportunity to purchase or construct those assets.

Industry Overview

Asphalt Industry

We provide asphalt terminalling services to marketers and distributors of liquid asphalt and asphalt-related products. We do not take title to the product; we lease certain facilities for operation by our customers and at some facilities we process, blend and manufacture products to meet our customers’ specifications. Our terminal network consists of 56 facilities located coast-to-coast throughout the United States.

Liquid asphalt, which includes liquid asphalt cement and residual fuel oils, is one of the oldest engineering materials. Liquid asphalt’s adhesive and waterproofing properties have been used for building structures, waterproofing ships, mummification and numerous other applications.

Production of liquid asphalt begins with the refining of crude oil. 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 liquid asphalt cement or residual fuel oil. Liquid asphalt production typically represents only a small portion of the total product production in the crude oil refining process. The liquid asphalt produced by petroleum distillation can be sold by the refinery either directly into the wholesale and retail liquid asphalt markets or to a liquid asphalt marketer.

In its normal state, liquid asphalt is too viscous to be used at ambient temperatures. For paving applications, asphalt can be heated (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 overlay 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, 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.

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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 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 marketers and finished asphalt product producers with access to 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.

Crude Oil Industry

We provide crude oil gathering, marketing, transportation 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 producing fields to transportation pipelines carrying crude oil to logistics hubs, such as the Cushing Interchange, where we have terminalling facilities that aid our customers in managing their crude oil.

Gathering, marketing and transportation. Pipeline transportation is generally considered the lowest cost and safest method for shipping crude oil and refined petroleum products to other locations. 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 other modes of transportation, such as truck, railroad, barge and tanker ship. Vessels and railroads provide additional transportation capabilities for shipping crude oil between gathering storage systems, pipelines, terminals 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. 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 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. Terminalling 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.

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 fees, also referred to as throughput fees, are generated when a terminal receives crude oil from a shipper and redelivers it to another shipper. Both storage fees and terminalling fees are earned from pipeline operators, refiners, gatherers and traders that need segregated storage, traders who make or take delivery under NYMEX contracts, and producers and marketers who seek to increase their marketing alternatives.

Overview of the Cushing Interchange. The Cushing Interchange, located in Cushing, Oklahoma, is one of the largest crude oil marketing hubs in the United States and the designated point of delivery specified in 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:

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

With 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.

Residual Fuel Oil Industry

Like liquid asphalt, 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 applications, including the utility industry, the shipping and paper industry, steel mills, tire manufacturing 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 facilities via numerous transportation methods, including truck, railroad, barge, and tanker ship. Some of our customers use our asphalt assets to service their residual fuel oil business.

Asphalt Terminalling Services

With approximately 10.3 million barrels of asphalt cement storage capacity, we are able to provide our customers the ability to effectively manage their liquid asphalt inventories while allowing significant flexibility in their processing and marketing activities. As of March 7, 2018, we have 56 terminals located in 26 states and, as such, are well-positioned to provide asphalt terminalling services in the market areas we serve throughout the continental United States.

We serve the asphalt industry by providing our customers access to their market areas through a combination of leasing our liquid asphalt facilities and providing terminalling services at certain facilities. We generate revenues by charging a fee for the lease of a facility or for services provided as asphalt products are terminalled in our facilities.

As of March 7, 2018, we have leases and storage agreements relating to all of our asphalt facilities. Lease and storage agreements related to 16 of these facilities have terms that expire by the end of 2018, while the agreements relating to our additional 40 facilities have on average approximately five years remaining under their terms. Fifteen of the contracts that expire in 2018 are with Ergon. 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. We operate the asphalt facilities that are contracted by storage, throughput and handling 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 those 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 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 is moved via heat-traced pipe into storage tanks. Those tanks are insulated and contain heating elements that allow the liquid asphalt to be stored in a heated state. The liquid asphalt 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. Depending 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 those 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 repairs of such asphalt facility are the responsibility of the lessee.

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

The following table provides an overview of our asphalt facilities as of March 7, 2018:

Location	Number of Facilities	Total Tankage (in thousands of bbls)[1]
Alabama	1	212
Arizona	1	66
Arkansas	1	21
California	1	66
Colorado	4	401
Georgia	2	192
Idaho	1	285
Illinois	2	232
Indiana	1	156
Kansas	5	662
Missouri	3	643
Mississippi	1	202
Montana	1	123
Nebraska	1	292
New Jersey	1	459
Nevada	1	280
North Carolina	1	259
Ohio	1	38
Oklahoma	7	1,409
Pennsylvania	1	59
Tennessee	5	1,596
Texas	6	1,001
Utah	2	300
Virginia	2	635

Washington	3	470
Wyoming	1	220
Total	56	10,279

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

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Our asphalt assets range in age from one year to over 50 years, and we expect that our storage tanks and related assets will have an average remaining life in excess of 20 years.

Significant Customers. For the year ended December 31, 2017, Ergon accounted for at least 45% but not more than 50% of our total asphalt terminalling services revenue. Asphalt & Fuel Supply, LLC accounted for at least 10% but not more than 15% of asphalt terminalling services revenue in 2017. The loss of either of those 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 terminalling services revenue during 2017. As of March 7, 2018, we have storage, throughput and handling agreements or operating leases with Ergon for 26 of our asphalt terminals. For more information regarding the Ergon agreements, please see "Item 13-Certain Relationships and Related-Party Transactions, and Director Independence-Agreements with Related Parties and Affiliates."

Crude Oil Terminalling Services

With approximately 6.9 million barrels of above-ground crude oil terminalling facilities, we are able to provide our customers with the ability to effectively manage their crude oil inventories and enhance flexibility in their marketing and operating activities. Our crude oil terminalling assets are located throughout our core operating areas, with the majority of our crude oil terminalling strategically located at the Cushing Interchange.

Our crude oil terminalling assets receive crude oil products from pipelines or trucks, including those owned by us, and distribute those 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 fees charged to customers.

As of March 1, 2018, we have approximately 5.4 million barrels of crude oil storage under service contracts, including 4.7 million barrels of crude oil storage contracts that are either month-to-month contracts or expire in 2018. The weighted average remaining term on the service contracts is approximately 11 months, with one contract having a remaining term of 47 months. Storage contracts with Vitol represent 2.2 million barrels of crude oil storage capacity under contract. 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.

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,	
	2016	2017
	(in thousands)	
Average crude oil barrels stored per month at our Cushing terminal	5,536	5,413
Average crude oil delivered (Bpd) to our Cushing terminal	78	41
Total storage capacity at our Cushing terminal (barrels at end of period)	6,600	6,600
Total other storage capacity (barrels at end of period)	834	337

The following table outlines the location of our crude oil terminals and their storage capacities and number of tanks as of December 31, 2017:

Location	Storage Capacity	Number of Tanks

	(thousands of barrels)	
Cushing, Oklahoma	6,600	34
Other[1]	337	177
Total	6,937	211

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

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 50 additional acres of land within the Cushing Interchange that is available for future expansion.

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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 14 years.

The design and construction specifications of our storage tanks meet or exceed the minimums established by the American Petroleum Institute (“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.

A key attribute of our Cushing terminal is that through our pipeline interface, we have access and connectivity to almost all of the terminals located within the Cushing Interchange. This connectivity is important 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 pipeline system as well as other terminals owned by Magellan Midstream Partners, Enterprise Products Partners, Sunoco Logistics Partners, Plains All American Pipeline, L.P., Seaway Crude Pipeline Company, LLC, Enbridge Energy Partners, L.P., SemGroup Corporation, Deeprock Energy Resources, LLC and two truck stations. 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 approximately 350,000 Bpd of crude oil.

Significant Customers. For the year ended December 31, 2017, Vitol accounted for at least 40% but not more than 45% of our total crude oil terminalling revenue, and Citigroup Energy, Inc. and MVP Logistics, LLC each accounted for at least 10% but not more than 25% of our total crude oil terminalling revenue. 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 terminalling revenue during 2017.

Crude Oil Pipeline Services

We own and operate a crude oil transportation system in the Mid-Continent region of the United States with a total length of approximately 655 miles. In addition, we purchase crude oil at production leases in Oklahoma, and we market those barrels primarily at the Cushing Interchange.

System	Asset Type	Approximate Length (miles)	Average Throughput for Year Ended December 31, 2016 (Bpd)	Average Throughput for Year Ended December 31, 2017 (Bpd)	Pipe Diameter Range
Mid-Continent	Gathering and transportation pipelines	655	26,505	21,931	4” to 20”

Mid-Continent Pipeline System. Our Mid-Continent pipeline system provides access to our Cushing terminal and other storage facilities. Our Mid-Continent pipeline system consists of approximately 655 miles of various sized pipeline, of which approximately 150 miles are currently idle, and has a capacity of approximately 25,000 Bpd. Crude oil delivered into the Oklahoma portion of our Mid-Continent pipeline system is transported to our Cushing terminal or delivered to local area refiners. The Mid-Continent pipeline system includes:

- an approximately 110-mile gathering and transportation system in southern Oklahoma acquired in November 2015 which has a capacity of 5,000 Bpd. Barrels transported on this pipeline are delivered to a single customer in southern Oklahoma;
-

an approximately 35-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; and

- an approximately 145-mile, 8-inch pipeline previously referred to as the Eagle North pipeline system. The throughput and deficiency agreement on our Eagle North pipeline system expired June 30, 2016. In July of 2016, because of the suspension of service of a portion of the Mid-Continent pipeline system, we completed a connection between our Mid-Continent and Eagle North pipeline systems and concurrently reversed the Eagle North pipeline system to deliver barrels from southern Oklahoma to Cushing, Oklahoma. As a result, we are currently operating one Oklahoma mainline system, which is a combination of both the Mid-Continent and Eagle North pipeline systems, instead of two separate systems.

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The Mid-Continent pipeline system was constructed in various stages beginning in the 1940s, and we believe it has a remaining life of at least 20 years. In late April 2016, as a precautionary measure we suspended service on a segment of our Mid-Continent pipeline system due to discovery of a pipeline exposure caused by heavy rains and the erosion of a riverbed in southern Oklahoma. There was no damage to the pipe and no loss of product. In the second quarter of 2016, we took action to mitigate the service suspension and worked with customers to divert volumes and, in certain circumstances, transported volumes to a third-party pipeline system via truck. We are working to restore service on the second Oklahoma pipeline system and expect to put the line back in condensate service by the end of the second quarter of 2018, increasing the transportation capacity of our pipeline systems by approximately 20,000 Bpd. The ability to fully utilize the capacity of these systems may be impacted by the market price of crude oil and producers' decisions to increase or decrease production in the areas we serve.

East Texas Pipeline System. We previously owned and operated the East Texas pipeline system, which is located in Texas. On April 18, 2017, we sold the East Texas pipeline system. We received cash proceeds at closing of approximately $4.8 million and recorded a gain of less than $0.1 million. For the years ended December 31, 2016 and 2017, our East Texas pipeline system gathered an average of approximately 9,146 Bpd and 2,937 Bpd, respectively, for the periods in which we owned the system.

Significant Customers. For the year ended December 31, 2017, CP Energy, LLC, CVR Energy, Inc. and Vitol each accounted for at least 20% but not more than 35% of crude oil pipeline services revenue. 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 2017.

Crude Oil Trucking and Producer Field Services

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

Crude Oil Trucking Services. To complement our pipeline gathering, marketing and transportation business, we use our approximately 65 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 27,000 Bpd and 21,000 Bpd for the years ended December 31, 2016 and 2017, respectively, from wellhead locations not served by pipeline gathering systems. The following table outlines the distribution of our trucking assets among our operating areas as of March 1, 2018:

Location	Number of Trucks
Oklahoma	45
Kansas	15
Texas	5
Total	65

During the second half of 2015, our West Texas operating margins and transported volumes were negatively impacted by increased competition from transporters moving equipment from crude oil shale areas to West Texas, where crude oil volumes have remained fairly steady and producers and marketers quickly pipe-connected barrels for transport, reducing the demand for trucking transportation. As a result, we decided to cease trucking barrels in West Texas and refocus our efforts on transporting barrels around our owned crude oil pipelines and storage assets in Oklahoma and Kansas. Due to this change, we recognized a $1.6 million restructuring expense in December 2015 comprised of employee severance costs and the recognition of future lease expense on idled equipment as of December 31, 2015. The severance costs were paid in the first quarter of 2016, and the lease payments will be made over the remaining lease terms, which extend through July 2019. See Note 6 to our consolidated financial statements for additional detail regarding this restructuring expense. Additionally, in December 2015 we recorded a $0.5 million impairment expense to write down the assets related to our West Texas trucking stations to their estimated fair value.

Producer Field Services. We provide various producer field services for companies such as DCP Operating Company, LP, Scout Energy Management, LLC and Regency Energy Partners, LP. These services include gas gathering pipeline maintenance, hot and cold fresh water delivery, chemical and downhole well treatment, wet oil cleanup, and separation facilities building and maintenance. In December 2017 we recorded a $2.4 million impairment expense to write down the carrying value of our assets related to our producer field services business to their estimated fair value.

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We provide these services at contracted hourly rates. Our producer service fleet consists of approximately 85 trucks in a number of different sizes.

Significant Customers. For the year ended December 31, 2017, MV Purchasing, LLC, Vitol and DCP Operating Company, LP each accounted for at least 10% but not more than 30% of crude oil trucking and producer field services revenue. 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 trucking and producer field services revenue during 2017.

Competition

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

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

With respect to our crude oil gathering and transportation services, our competitors include Enterprise Products Partners L.P., Plains All American Pipeline, L.P., Magellan Midstream Partners, L.P., Sunoco Logistics Partners L.P. and Rose Rock Midstream Partners, L.P., among others. With respect to our crude oil terminalling services, our competitors include Magellan Midstream Partners, L.P., Enbridge Energy Partners, L.P., Enterprise Products Partners L.P., Plains All American Pipeline, L.P. and Rose Rock Midstream Partners, 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., Magellan Midstream Partners, L.P. and Rose Rock 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/or
- a decision by our competitors to acquire or construct crude oil midstream assets and provide gathering, transportation or terminalling services in geographic areas, or to customers, served by our assets and services.

If we are unable to compete effectively with services offered by other midstream enterprises, our financial results and 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.

Pipeline Regulation

We currently do not offer interstate transportation service regulated by the Federal Energy Regulatory Commission ("FERC") with the exception of two short interstate segments where the sole shipper is our affiliate. Our interstate pipeline segments are subject to regulatory enforcement by the U.S. Department of Transportation's ("DOT") Pipeline Hazardous Materials Safety Administration ("PHMSA").

Gathering and Intrastate Pipeline Regulation. All 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.

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. The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (“Pipeline Safety Act”) was enacted in January 2012. That legislation increased the maximum civil penalties for pipeline safety administrative enforcement actions; required 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; required pipeline operators to verify their records on maximum allowable operating pressure; and imposed new emergency response and incident notification requirements. In 2016, the Pipeline Safety Act was reauthorized and amended to add additional construction inspection requirements, clarify integrity management rules and update federally incorporated standards. On January 23, 2017, PHMSA published a final rule that became effective on March 24, 2017. This rule amended the Pipeline Safety Act to include, among other provisions, a specific time frame for notifying PHMSA of accidents and incidents, allowance for PHMSA to recover costs associated with design reviews of new projects, renewal of expiring special permits, processes for requesting protection of confidential commercial information, changes to the drug and alcohol testing requirements and incorporating consensus standards by reference for in-line inspection and stress corrosion cracking direct assessment. The states in which we operate pipelines 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, is 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 (“OSHA”), with respect to our trucking operations.

Environmental, Health and Safety Risks

General. Our midstream crude oil gathering, transportation and terminalling operations, as well as 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, health and safety. Various permits or other authorizations are required under these laws for the operation of our terminals, pipelines and related operations, and may be subject to revocation, modification and renewal. These laws and regulations may also require notice to stakeholders of proposed and ongoing operations; require the installation of expensive pollution control equipment; restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with transporting through pipelines; or establish specific safety and health criteria addressing worker protection. As with liquid asphalt and midstream 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/or criminal penalties, the imposition of investigatory and remedial liabilities and 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, regulations and permits. However, environmental laws and regulations are subject to change, along with varying degrees of interpretation and departmental policies, resulting in potentially more stringent requirements. The recent legislative and regulatory trend has been to place increasingly stringent restrictions and limitations on activities that may affect the environment. Federal, state or local administrative decisions, developments in the federal or state court systems or other governmental or judicial actions may influence the interpretation and/or enforcement of environmental laws and regulations and may thereby increase compliance costs. 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, financial position or cash flows.

Risks of accidental releases into the environment, such as leaks or spills of petroleum products or hazardous materials from our terminals, pipelines and trucks, are inherent in the nature of both our liquid asphalt and midstream operations. 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 cleanup 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.

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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 ("CWA") and analogous state and local laws impose restrictions, strict controls and permitting requirements on the discharge of pollutants into waters of the United States and state waters. We note that the term "waters of the United States" is already broadly construed and, in 2015, the United States Environmental Protection Agency ("EPA") and U.S. Army Corps of Engineers adopted a rule to clarify the meaning of the term "waters of the United States." Many interested parties believe that the rule expands federal jurisdiction under the CWA. In January 2018, the Supreme Court ruled that district courts have jurisdiction over challenges to the rule. Litigation surrounding this rule is ongoing, and the EPA has instituted rulemakings to both delay the effective date of the rule and to repeal the rule. Although the outcome of these legal challenges remains uncertain, with the change in administration, the "waters of the United States" rule is not currently expected to survive those challenges. The CWA and analogous laws provide significant penalties for unauthorized discharges and impose substantial potential liabilities for cleaning up releases into water. In addition, the CWA 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 ("OPA"), was enacted in 1990 and amended provisions of the Federal Water Pollution Control Act of 1972, the CWA 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 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 applicable 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." The EPA approved final rules under the CAA that established new air emission controls for oil and natural gas production, pipelines and processing operations that took effect on October 15, 2012. To respond to challenges, the EPA revised certain aspects of the rules and has indicated it may reconsider other aspects. The EPA finalized a rule, which took effect August 2, 2016, to set standards for methane and volatile organic compound emissions from new and modified sources in the oil and gas sector, including transmission. The EPA is currently engaged in rulemaking to stay the effective date of these rules. The costs of compliance with any modified or newly issued rules cannot be predicted. The Obama administration also announced in January 2015 that other federal agencies, including the Bureau of Land Management ("BLM"), PHMSA and the Department of Energy, will impose new or more stringent regulations on the oil and gas sector that are said to have the effect of reducing methane emissions. For example, the BLM adopted rules that took effect on January 17, 2017, to reduce venting, flaring and leaks during oil and natural gas production activities on onshore federal and Indian leases. In December 2017, implementation of this rule was delayed until January 2019. Compliance with these 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. However, the status of recent and future rules and rulemaking initiatives under the new administration is uncertain. Although we can provide no assurance, we believe future compliance with the CAA, as currently 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, the U.S. Congress, in the past, has considered but not enacted federal legislation requiring GHG controls. The EPA has adopted regulations under existing provisions of the CAA that require Prevention of Significant Deterioration (“PSD”) pre-construction permits, and Title V operating permits for GHG emissions from certain large stationary sources. Furthermore, in 2009, the EPA adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States., including, among others, certain onshore oil and natural gas processing and fractionating facilities. Monitoring obligations began in 2010 and the emissions reporting requirements took effect in 2011. These EPA rulemakings could affect our operations and ability to obtain air permits for new or modified facilities. In addition, efforts have been and continue to be made in the international community toward the adoption of international treaties or protocols. In 2015, the United States participated in the United Nations Conference on Climate Change, which led to the adoption of the Paris Agreement that will require countries to review and "represent a progression" in their intended nationally determined contributions, which set GHG emission reduction goals, every five years beginning in 2020. However, in June 2017, President Trump announced that the United States plans to withdraw from the Paris Agreement and to seek negotiations either to reenter the Paris Agreement on different terms or establish a new framework agreement. The Paris Agreement provides for a four-year exit process beginning in November 2016, which would result in an effective exit date of November 2020. The United States's adherence to the exit process and/or the terms on which the United States may reenter the Paris Agreement or a separately negotiated agreement are unclear at this time. Due to the uncertainties surrounding the regulation of and other risks associated with GHG emissions, we cannot predict the financial impact of related developments on our operations.

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 do not expect we would be impacted to a greater degree than other similarly situated midstream transporters of petroleum products, the greenhouse gas control programs 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-related physical changes or changes in weather patterns. Severe weather 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 customers' operations. These types of physical changes could also affect entities that provide goods and services to us, and indirectly have an adverse effect 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 ("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 and certain former owners and operators 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 fall within CERCLA's hazardous substance definition. 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 (“RCRA”), as well as to comparable state and local laws. While normal costs of complying with these laws 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 exemption for certain oil and gas “exploration and production” waste were eliminated. For example, in 2016, the EPA and certain environmental organizations entered into a consent decree which requires the EPA to propose a rulemaking no later than March 15, 2019, for the revision of criteria regulations pertaining to exempted oil and gas wastes or to sign a determination that revision of the regulations is not necessary. Should any oil and gas exploration and production 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, transported or stored or have been handled, transported or stored for many years. Although we believe that operating and disposal practices that were standard in the liquid asphalt, midstream and field services industries at the time were utilized at properties leased or owned by us, historical releases of hazardous substances or associated generated wastes may have occurred on or under the properties owned

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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 released 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 in the liquid asphalt and midstream 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 may experience releases of hazardous materials, including petroleum products, into the environment from our pipeline terminalling 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.

Regulation of Hydraulic Fracturing. A portion of our customers' production is developed from unconventional sources, such as shales, that require hydraulic fracturing as part of the production process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into shale formations to stimulate crude oil and/or natural gas production. The practice of hydraulic fracturing has been subject to public scrutiny in recent years and various efforts to regulate, or in some cases prohibit, hydraulic fracturing have been pursued at the local, state and federal levels of government, and may be pursued in the future. For example, several states, including states in which we operate, have imposed disclosure requirements on hydraulic fracturing, and several local governments have prohibited or severely restricted hydraulic fracturing within their jurisdictions. Restrictions on hydraulic fracturing could adversely affect our operations by reducing the volumes of crude oil that we transport.

Seismicity Related to Wastewater Disposal Wells. Wastewater injection into disposal wells has been tied to increased seismic activity in Oklahoma and other producing states. In some seismically active areas, regulators have responded with permanent and temporary restrictions on the volume and rate of wastewater injection into disposal wells. Such restrictions on wastewater disposal wells or taxation imposed on injected fluids could have a negative impact on us and others in the industry.

Endangered Species and Migratory Birds. The Endangered Species Act ("ESA"), restricts activities that may affect endangered or threatened species or their habitats. While some of our operations may be located in areas that are designated as habitats for endangered or threatened species, we believe that we are in substantial compliance with the ESA. However, the designation of previously unlisted endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans or limit future development in the affected areas. The Migratory Bird Treaty Act ("MBTA"), implements various treaties and conventions between the United States and certain other nations for the protection of migratory birds. Pursuant to the MBTA, the taking, killing or possessing of migratory birds is unlawful without a permit, thereby potentially requiring the implementation of operating restrictions or a temporary, seasonal, or permanent ban in affected areas. We believe that we are in substantial compliance with the MBTA.

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 and industry standards, record keeping requirements and monitoring of occupational exposure to regulated substances.

National Environmental Policy Act. The National Environmental Policy Act (“NEPA”) requires federal agencies, including the EPA and Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an environmental assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed environmental impact statement that may be made available for public review and comment. This process has the potential to delay or even halt the development oil and natural gas projects.

Anti-Terrorism Measures. The federal Department of Homeland Security Appropriations Act of 2007 (“Appropriations Act”) requires the Department of Homeland Security (“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 Appropriations Act and, on

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November 20, 2007, issued an Appendix A to CFATS that established chemicals of interest and their respective threshold quantities that trigger compliance with the interim rules. In December 2014, the Protecting and Securing Chemical Facilities from Terrorist Attacks Act of 2014 (“CFATS Act”) was enacted. The CFATS Act reauthorized the CFATS program for four years. The CFATS program utilizes a Chemical Security Assessment Tool (“CSAT”) to identify chemical facilities potentially deemed “high risk.” The first step of CSAT is user registration, followed by the completion of a top-screen evaluation. The top-screen evaluation analyzes whether a facility stores regulated chemicals above specified thresholds. If it does, the facility must complete a Security Vulnerability Assessment, which identifies a facility’s security vulnerabilities, and develop and implement a Site Security Plan, which must include measures that satisfy the identified risk-based performance standards. DHS must review and approve or deny all security vulnerability assessments and site security plans. CFATS also requires regulated facilities to keep detailed security records and allow DHS the right to enter, inspect, and audit the property, equipment, operations and records of such facilities. We believe we are in substantial compliance with the CFATS program at our facilities that handle, store, use or process COI above the applicable threshold.

Operational Hazards and Insurance

Terminals, pipelines 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 maintain insurance of various types and varying levels of coverage which 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 terminals, pipelines and other facilities. The overall cost of the insurance program has decreased over the last five years due to favorable claims history, improved risk management practices, collaborative relationships with our underwriters and competitive insurance markets. 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. We continue to monitor our retentions as they relate to the overall cost and scope of our insurance program.

Employees

As of December 31, 2017, we employed approximately 370 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.

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 20 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 which 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.

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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 $10.9 million per quarter, or $43.7 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 4.7 million barrels of storage at this location are month-to-month or expire in 2018. 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 financial condition, results of operations and cash flows.

We rely on certain key customers for a portion of revenues. For example, Ergon Asphalt & Emulsions, Inc., a wholly-owned subsidiary of Ergon, Inc., represented approximately $56.4 million, or 50%, of our total asphalt terminalling services revenue in 2017. Vitol represented approximately $8.9 million, or 40%, of our total crude oil terminalling revenue, $6.4 million, or 30%, of our crude oil pipeline services revenue and $5.9 million, or 24%, of our total crude oil trucking and producer field services revenue in 2017. Vitol and Ergon are private companies and we have limited information regarding their financial condition. Vitol and Ergon Asphalt & Emulsions, Inc. comprised 9% and 29%, respectively, of total accounts receivable at December 31, 2017.

In addition to Vitol and Ergon Asphalt & Emulsions, Inc., we have other key customers. Asphalt & Fuel Supply, LLC accounted for at least 10% but not more than 15% of total asphalt terminalling services revenue in 2017. Citigroup Energy, Inc. and MVP Logistics, LLC each accounted for at least 10% but no more than 25% of total crude oil terminalling revenue in 2017. MV Purchasing, LLC and DCP Operating Company, LP each accounted for at least 10% but no more than 30% of total crude oil trucking and producer field services revenue in 2017. CP Energy, LLC and CVR Energy, Inc. each accounted for at least 20% but no more than 35% of total crude oil pipeline services revenue in 2017.

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 which 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

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or to enforce performance of obligations under contractual arrangements. Additionally, many of our customers finance their activities through cash flows from operations, the incurrence of debt or the issuance of equity. The reduction of cash flows resulting from declines in commodity prices, a reduction in borrowing bases under credit facilities, the lack of availability of debt or equity financing or any combination of such factors 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, unit price, 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, including risks relating to commodity price deterioration or other conditions in the energy industry. In addition, any material nonpayment or nonperformance by our customers could require us to pursue substitute customers for our affected assets or to provide alternative services. Any such efforts may not be successful, may be expensive to undertake and may not provide similar fees. These events could have a material adverse effect on our financial condition, results of operations and cash flows.

The amount of cash we have available for distribution to holders of our units depends primarily on our cash flows 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 flows 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, 2017, we had approximately $309.1 million in outstanding indebtedness, including approximately $1.5 million in outstanding letters of credit, under our $450.0 million credit agreement. Our level of debt under the credit agreement 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 flows 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 agreement 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.

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Restrictions in our credit agreement could materially adversely affect our business, financial condition, results of operations, ability to make cash distributions to unitholders and value of our units.

We are dependent upon the earnings and cash flows generated by our operations to meet our debt service obligations and to make cash distributions to our unitholders. The operating and financial restrictions and covenants in our credit agreement and any future financing agreements could restrict our ability to finance future operations or capital needs or to expand or pursue our business activities, which may, in turn, limit our ability to make cash distributions to our unitholders. For example, our credit agreement restricts our ability to, among other things:

- incur or guarantee certain additional debt;
- make certain cash distributions on or redeem or repurchase certain units;
- make certain investments and acquisitions;
- make certain capital expenditures;
- incur certain liens or permit them to exist;
- enter into certain types of transactions with affiliates;
- merge or consolidate with another company or otherwise engage in a change of control transaction; and
- transfer, sell or otherwise dispose of certain assets.

Our credit agreement also contains covenants requiring us to maintain certain financial ratios and meet certain financial tests. Our ability to meet those financial ratios and financial tests can be affected by events beyond our control, and we cannot guarantee that we will meet those ratios and tests.

The provisions of our credit agreement may affect our ability to obtain future financing and pursue attractive business opportunities as well as affect our flexibility in planning for, and reacting to, changes in business conditions. In addition, a failure to comply with the provisions of our credit agreement could result in a default or an event of default that could enable our lenders to declare the outstanding principal of that debt, together with accrued and unpaid interest, to be immediately due and payable. If we were unable to repay the accelerated amounts, the lenders under our credit agreement could proceed against the collateral granted to them to secure such debt. If the payment of our debt is accelerated, our assets may be insufficient to repay such debt in full, and our unitholders could experience a partial or total loss of their investment. The credit agreement also has cross default provisions that apply to any other indebtedness we may have, and the indentures have cross default provisions that apply to certain other indebtedness.

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

As of March 1, 2018, we have aggregate unused credit availability under our credit agreement of approximately $139.9 million, although our ability to borrow such funds may be limited by the financial covenants in our credit agreement, and cash on hand of approximately $1.3 million. Our ability to access the public capital markets on terms acceptable to us or at all may be limited due to, among other things, commodity price volatility and deterioration, general economic conditions, rising interest rates, capital market volatility, the uncertainty of our future cash flows, adverse business developments 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 on terms acceptable to us or at all, and may increase significantly the costs of financing our growth potential.

If we fail to raise additional capital or an event of default occurs 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, unit price and results of operations. In addition, if we are unable to access the capital markets for acquisitions or expansion projects on terms acceptable to us or at all, or if the financing cost related to any such acquisitions or expansion projects increases, it may have a material adverse effect on our business, cash flows, ability to make distributions to our unitholders, unit price, 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 agreement. In addition, any amounts borrowed for permitted distributions to our unitholders will reduce the

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funds available to us for other purposes under our credit agreement, 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 liquid asphalt and crude oil prices. However, the volumes of liquid asphalt and crude oil we terminal, gather, market or transport are affected by commodity prices because many of our customers have direct commodity price exposure. Many of our customers have been, and continue to be, adversely affected by significant changes in commodity prices. If our customers continue to be negatively impacted by commodity price volatility, a sustained period of depressed commodity prices or other adverse conditions of the energy industry, they may, among other things, decrease the amount of services that we provide to them. The prices of liquid asphalt and crude oil 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.

Our contracts with some of our customers 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 and 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 terminalling, gathering, pipeline transportation and trucking activities. Competition from other providers of crude oil gathering, pipeline transportation, terminalling and trucking 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 terminalling services contracts have short terms, and certain leases relating to our asphalt operations may be terminated upon short notice.

As of March 7, 2018, we had leases or storage agreements with third-party customers relating to each of our 56 asphalt facilities. Lease or storage agreements related to 16 of these facilities have terms that expire by 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 on terms acceptable to us or at all. In addition, certain key customers account for a significant portion of our asphalt terminalling services revenues, the loss of which could result in a significant 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 agreement 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 from third parties. 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 terminalling services, which could have a material adverse effect on our business, cash flows, ability to make distributions to our unitholders, unit price, 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 operate under expired 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 expired 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.

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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, unit price, results of operations and ability to conduct our business.

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

A sustained decrease in demand for liquid asphalt and/or crude oil products in the areas served by our terminalling 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 liquid asphalt and crude oil products include:

- lower demand by consumers for refined products, including asphalt products, as a result of (i) recession or other adverse economic conditions; (ii) higher prices caused by an increase in the market price of crude oil; or (iii) higher taxes or other governmental or regulatory actions that increase, directly or indirectly, the cost of gasoline or other refined products; and
- 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.

Certain of our pipeline and field 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 transported by our operations. As a result, we may experience declines in our margin and profitability if our volumes decrease.

A material decrease in the production of liquid asphalt 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 produced from the various liquid asphalt producing refineries. Liquid asphalt production may decline for a number of reasons, including refiners processing more light, sweet crude oil or refiners installing coker units which further refine heavy residual fuel oil bottoms such as liquid asphalt. 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, our throughput could decline, reducing our revenue and cash flows and adversely affecting our financial condition and results of operations.

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 and demand for transportation and storage of 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 commodity prices remain depressed for any sustained period of time, production may slow and our customers may decrease the volumes we transport or store for them. 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 flows 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.

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We face intense competition in our terminalling, gathering and transportation activities. Competition from other providers of crude oil terminalling, gathering and transportation 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 terminalling, gathering, and transportation 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, 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. 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.

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.

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 which would adversely affect our revenue, cash flows 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. Ergon has indicated that it intends to use us as a growth vehicle to pursue the acquisition and expansion of midstream energy businesses and assets. We cannot say with any certainty whether or not Ergon 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.

We may also make acquisitions directly from third parties. If we are unable to make accretive acquisitions because we are (i) unable to acquire projects from such a development company when they are available; (ii) unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them; (iii) unable to obtain financing for these acquisitions on economically acceptable terms; or (iv) outbid by competitors, then our future growth and ability to increase distributions may 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 likely 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.

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

We may acquire assets that have operations in new and distinct lines of business from our liquid asphalt or crude oil 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 which 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 condition and prospects. Furthermore, new lines of business may subject us to additional business and operating risks. For example, we may in the future determine to acquire businesses that are subject to direct exposure 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 and budgets, 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 within the budgeted cost. Moreover, we may construct facilities to capture anticipated future growth in demand in a market in which such growth does not materialize.

Our expansion projects may not immediately produce operating cash flows.

Expansion projects require us to make significant capital investments over time and we will incur financing costs during the planning and construction phases of these projects; however, the operating cash flows we expect these projects to generate will not materialize, if at all, until sometime after the projects are completed and placed into service. As a result, to the extent we finance our projects with borrowings, our leverage may increase during the period prior to the generation of those operating cash flows and, to the extent we finance our projects with equity, our cash available for distribution on a common unit basis may decrease during the period prior to the generation of those operating cash flows. If we experience unanticipated or extended delays in generating operating cash flows from construction projects, or if such operating cash flows do not materialize as expected, we may need to reduce or reprioritize our capital budget in order to meet our capital requirements, and our liquidity and capital position could be adversely affected.

We may incur significant costs and liabilities as a result of pipeline integrity management program requirements 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 pipelines that could affect "high consequence areas" including populated areas, areas that are unusually sensitive to environmental damage and commercially navigable waterways. 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.

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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, the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 ("PIPES") was enacted. PIPES reauthorized and amended the DOT's pipeline safety programs and included a provision eliminating the regulatory exemption for low-stress hazardous liquid pipelines. The Pipeline Safety Act established additional safety requirements for newly constructed pipelines and required the DOT to study safety issues that could result in the adoption of additional regulatory requirements for existing pipelines. On August 13, 2012, PHMSA published rules to update pipeline safety regulations, including increasing maximum civil penalties from $0.1 million to $0.2 million per day of violation and from $1.0 million to $2.0 million total for a related series of violations, as well as changing PHMSA's enforcement process. This maximum penalty authority established by statute has been and will continue to be adjusted periodically to account for inflation. PHMSA also issued an Advisory Bulletin in May 2012 which advised pipeline operators that they must have records to document the maximum operating pressure for each section of their pipeline and that the records must be traceable, verifiable and complete. Locating such records and, in the absence of any such records, verifying maximum pressures through physical testing (including hydrostatic testing) or modifying or replacing facilities to meet the demands of verifiable pressures, could significantly increase an operator's costs of compliance. On January 23, 2017, PHMSA published a final rule that became effective on March 24, 2017. This rule amended the Pipeline Safety Act to include, among other provisions, a specific time frame for notifying PHMSA of accidents and incidents, allowance for PHMSA to recover costs associated with design reviews of new projects, renewal of expiring special permits, processes for requesting protection of confidential commercial information, changes to the drug and alcohol testing requirements and incorporating consensus standards by reference for in-line inspection and Stress Corrosion Cracking Direct Assessment. Please read "Item 1. Business-Pipeline Regulation-Pipeline Safety" for more information.

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 operations 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. Violators of environmental laws and regulations are subject to administrative, civil and criminal penalties, including civil fines, injunctions or both. We may experience delays in obtaining, or be unable to obtain, required environmental permits, which may delay or interrupt our operations and limit our growth and revenue. Joint and several strict liability may be incurred without regard to the legality of the original conduct under CERCLA, RCRA and analogous state laws for the remediation of contaminated areas. Private parties also may have the right to pursue legal actions to enforce compliance, as well as to seek damages for non-compliance, with environmental laws and regulations or for personal injury or property damage. Moreover, new laws, regulations or enforcement policies could be implemented that significantly increase our compliance costs and the costs of any remediation that may become necessary, some of which may be material.

We incur environmental costs and liabilities in connection with the handling of hydrocarbons and solid wastes. We currently own, operate or lease properties which for many years have been used for asphalt activities and midstream activities, including properties in and around the Cushing Interchange. Activities by us or by 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 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-Environmental, Health, and Safety Risks” for more information.

In addition, the workplaces associated with the terminalling 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.

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Adoption of legislation and regulatory measures targeting 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 has been considered in the past but has not been enacted. The EPA has adopted regulations under existing provisions of the CAA which require PSD pre-construction permits and Title V operating permits for GHG emissions from certain large stationary sources. 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. Furthermore, in 2009, the EPA adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States, including, among others, certain onshore oil and natural gas processing and fractionating facilities. Monitoring obligations began in 2010 and the emissions reporting requirements took effect in 2011. Some of our facilities include natural gas-fired combustion units which may become subject to this rule. These facilities are 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 of our facilities, it has caused us to incur monitoring and reporting costs relating to GHG emissions. We also note, as previously mentioned, that the EPA finalized rules that took effect in August 2016 to set standards for methane and volatile organic compound emissions from new and modified sources in the oil and gas sector, including transmission. However, the EPA is currently engaged in rulemaking to stay the effective date of these rules. 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 costs 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-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 customers' operations. These kinds of physical changes could also affect entities that provide goods and services to us and indirectly have an adverse effect 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. Finally, increasing attention to the risks of climate change has resulted in an increased possibility of lawsuits brought by public and private entities against oil and gas companies in connection with their greenhouse gas emissions. Should we be targeted by any such litigation, we may incur liability which, to the extent that societal pressures or political or other factors are involved, could be imposed without regard to our causation of or contribution to the asserted damage, or to other mitigating factors.

A portion of our customers' production is developed from unconventional sources, such as shales, which require hydraulic fracturing as part of the production process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into shale formations to stimulate crude oil and/or gas production. The practice of hydraulic fracturing has been subject to public scrutiny in recent years and various efforts to regulate, or in some cases prohibit, hydraulic fracturing have been pursued at the local, state and federal levels of government and may be pursued in the future. For example, several states, including states in which we operate, have imposed disclosure requirements on hydraulic fracturing, and several local governments have prohibited or severely restricted hydraulic fracturing within their jurisdictions. Restrictions on hydraulic fracturing could adversely affect our operations by reducing the volumes of crude oil that we transport.

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Additionally, the ESA restricts activities that may affect endangered or threatened species or their habitats. While some of our operations may be located in areas that are designated as habitats for endangered or threatened species, we believe that we are in substantial compliance with the ESA. However, the designation of previously unlisted endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans or limit future development in the affected areas. The MBTA implements various treaties and conventions between the United States and certain other nations for the protection of migratory birds. Pursuant to the MBTA, the taking, killing or possessing of migratory birds is unlawful without a permit, thereby potentially requiring the implementation of operating restrictions or a temporary, seasonal or permanent ban in affected areas. We believe that we are in substantial compliance with the MBTA, but noncompliance could result in fines or operational prohibitions which could adversely affect our financial condition, results of operations and cash flows.

Please also see “Item 1. Business-Environmental, Health and Safety Risks-Climate.”

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 terminalling of crude oil and the terminalling of liquid asphalt cement, including:

- explosions, earthquakes, fires and 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 and other areas of the United States in which we operate;
- damage to our terminals, pipelines and 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 facilities and pipelines are located, which could disrupt our operations.

We do not own all of the land on which our asphalt and crude oil facilities and pipelines 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 rights-of-way or any material real property leases are invalid, lapse or terminate. We obtain the rights to construct and operate some of our asphalt and crude oil facilities and pipelines 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 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 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 prove 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.

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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 costs 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.

Terrorist or cyber-attacks and threats, escalation of military activity in response to these attacks or acts of war could have a material adverse effect on our business, financial condition or results of operations.

Terrorist attacks and threats, cyber-attacks, escalation of military activity or acts of war may have significant effects on general economic conditions, fluctuations in consumer confidence and spending and market liquidity, each of which could materially and adversely affect our business. Terrorist or cyber-attacks, rumors or threats of war, actual conflicts involving the United States or its allies or military or trade disruptions may significantly affect our operations and those of our customers. Strategic targets, such as energy-related assets, may be at greater risk of future attacks than other targets in the United States. We do not maintain specialized insurance for possible exposures resulting from a cyber-attack on our assets that may shut down all or part of our business. Disruption or significant increases in energy prices could result in government-imposed price controls. It is possible that any of these occurrences, or a combination of them, could have a material adverse effect on our business, financial condition and results of operations.

Risks Inherent in an Investment in Us

Ergon controls 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.

Ergon owns and controls our General Partner. Some of our General Partner's directors are directors and officers of Ergon. 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 or Ergon to pursue a business strategy that favors us. Such persons may make 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 and our unitholders, such as Ergon and its 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.

- Ergon is a holder of our Preferred Units and may favor its own 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.
- Ergon may compete with us, including with respect to future acquisition opportunities.
- Ergon may favor its own interests in proposing the terms of any acquisitions we make directly from them, and such terms may not be as favorable as those we could receive from an unrelated third party.
- Our General Partner has limited liability and reduced fiduciary duties and our unitholders have restricted remedies available for actions that, without the limitations, might constitute breaches of fiduciary duty.

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- 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.
- Our General Partner decides whether to retain separate counsel, accountants or others to perform services for us.

Our partnership agreement limits the fiduciary duties our General Partner owes 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.

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Ergon 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 Ergon prohibits Ergon from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, Ergon may acquire, construct or dispose of assets in the future, without any obligation to offer us the opportunity to purchase or construct any of those assets. Ergon is a privately held company engaged in a wide range of operations. Ergon has significantly greater resources and experience than we have, which may make it more difficult for us to compete with Ergon with respect to commercial activities as well as for acquisition candidates. As a result, competition from Ergon 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 is 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 Ergon. 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 Ergon, the owner of our General Partner, from transferring all or a portion of its 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 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 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 may have any or all of the following effects, among others:

- 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.
- The market price of the common units may decline.

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

Unitholders' voting rights are further restricted by the partnership agreement, which provides 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 our public unitholders are dissatisfied with our General Partner, it will be difficult for them to remove our General Partner without its consent.

It will be difficult for our public unitholders to remove our General Partner without its consent because our General Partner and its affiliates own a substantial number of our units. 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 March 1, 2018, Ergon owned approximately 28.3% 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 1, 2018, the executive officers and directors of our General Partner beneficially own an aggregate of 1,037,212 common units and 20,400 Preferred Units and Ergon owns 3,049,187 common units and 18,312,968 Preferred Units. The sale of these units in the public markets could have an adverse impact on the public trading 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 the 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 March 1, 2018, Ergon owned 52.1% of our outstanding Preferred Units.

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 preferred 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.

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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 to force the conversion of all outstanding Preferred Units to common units. These circumstances include a situation in which if the holders of a certain number of Preferred Units elect to convert the Preferred Units that they hold to common units, we could then force all remaining outstanding Preferred Units to convert to common units. Ergon, the owner of our General Partner, owns enough Preferred Units such that if they were all converted to common units, we would be able to exercise this mandatory conversion right. In addition, we also have the right, effective October 25, 2015, to force the conversion of the outstanding Preferred Units at any time if (i) the daily volume-weighted average trading price of our common units is greater than $8.45 for 20 out of the trailing 30 trading days ending two trading days before we furnish notice of conversion and (ii) the average trading volume of our common units has exceeded 20,000 common units for 20 out of the trailing 30 trading days ending two trading days before we furnish notice of conversion. In addition, the conversion provisions may be modified with the consent of a majority of the outstanding Preferred Units. As of March 1, 2018, Ergon owned 52.1% of our outstanding Preferred Units and has the ability to consent to amendments to such conversion provisions. 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.

Ergon, as the holder of a majority of the outstanding Preferred Units, has the ability to consent to the amendments to the provisions of the Preferred Units.

The Preferred Units have voting rights that are identical to the voting rights of common units and vote with the common units as a single class, so that each Preferred Unit is entitled to one vote for each common unit into which such Preferred Unit is convertible on each matter with respect to which each common unit is entitled to vote. In addition, the approval of a majority of the Preferred Units, voting separately as a class, is necessary on any matter that adversely affects any of the rights of the Preferred Units or amends or modifies the terms of the Preferred Units in any material respect or affects the holders of the Preferred Units disproportionately in relation to the holders of common units, including, without limitation, any action that would (i) reduce the distribution amount to the Preferred Units or change the time or form of payment of distributions, (ii) reduce the amount payable to the Preferred Units upon the liquidation of our partnership, (iii) modify the conditions relating to the conversion of the Preferred Units or (iv) issue any equity security that, with respect to distributions or rights upon liquidation, ranks equal to or senior to the Preferred Units or issue any additional Preferred Units. As of March 1, 2018, Ergon owned 52.1% of our outstanding Preferred Units and has the ability to consent to amendments to the terms of the Preferred Units without the consent of other unitholders.

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.

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 U.S. federal income taxation on the income generated by us or entities not subject to U.S. 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

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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.

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:

- 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.

If we fail to maintain an effective system of internal controls, we may not be able to accurately report our financial results or prevent fraud. In addition, potential changes in accounting standards might cause us to revise our financial results and disclosure in the future.

Effective internal controls are necessary for us to provide timely and reliable financial reports and effectively prevent fraud. If we cannot provide timely and reliable financial reports or prevent fraud, our reputation and operating results would be harmed. We continue to enhance our internal controls and financial reporting capabilities. These enhancements require a significant commitment of resources, personnel and the development and maintenance of formalized internal reporting procedures to ensure the reliability of our financial reporting. Our efforts to update and maintain our internal controls may not be successful, and we may be unable to maintain adequate controls over our financial processes and reporting now or in the future, including future compliance with the obligations under Section 404 of the Sarbanes-Oxley Act of 2002. As further described below in “Internal Control Over Financial Reporting,” as of December 31, 2017, we have identified a material weakness in our internal control over financial reporting. Any failure to maintain effective controls or difficulties encountered in the effective improvement of our internal controls could prevent us from timely and reliably reporting our financial results

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and may harm our operating results. Ineffective internal controls could also cause investors to lose confidence in our reported financial information. In addition, the Financial Accounting Standards Board or the SEC could enact new accounting standards that might impact how we are required to record revenues, expenses, assets and liabilities. Any significant change in accounting standards or disclosure requirements could have a material effect on our business, results of operations, financial condition and ability to comply with our debt obligations.

Tax Risks to Unitholders

Recently enacted tax legislation as well as future tax legislation may adversely affect our business, financial condition, results of operations and cash flows.

On December 22, 2017, the President signed into law the 2017 budget reconciliation act commonly referred to as the Tax Cuts and Jobs Act (the "TCJA"), which makes significant changes to U.S. federal income tax laws. Among other changes, the TCJA (i) introduces a new deduction on certain pass-through income, (ii) repeals the partnership technical termination rule, (iii) imposes a new limitation on the deductibility of interest expense, (iv) reduces the corporate tax rate to 21% and (v) limits the amount of net operating losses that are available to offset the taxable income of our corporate subsidiaries. The TCJA is complex and far-reaching and could have an adverse effect on our business, financial condition, results of operations and cash flows.

Our common unitholders have been and will be required to pay taxes on their share of our taxable income even if they have not received 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 us 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 21%, 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 flows and after-tax return to unitholders and thus would likely result in a substantial reduction in the value of our units.

In addition, changes to the audit procedures for large partnerships and in certain circumstances for tax years beginning after 2017 would permit the IRS to assess and collect taxes (including any applicable penalties and interest) resulting from partnership-level federal income tax audits directly from us in the year in which the audit is completed. If we are required to make payments of taxes, penalties and interest resulting from audit adjustments, our cash available for distribution to our unitholders might be substantially reduced. Moreover, changes in current state law may subject us to entity-level taxation by individual states. 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 on our total revenue, as adjusted and apportioned to the state under the applicable Texas rules and regulations, at a maximum effective tax rate of 0.525%. 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.

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Our partnership agreement provides that if a law is enacted or an 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. No such adjustments have been made to date, but there can be no assurance that no such adjustments will be made in the future.

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.

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

In the case of taxpayers subject to the passive activity loss rules (generally individuals, closely-held corporations and regulated investment companies), any losses generated by us will only be available to offset our future income and cannot be used to offset income from other activities, including other passive activities or investments. Unused losses may be deducted when the unitholder disposes of the unitholder’s entire investment in us in a fully taxable transaction with an unrelated party. A unitholder’s share of our net passive income may be offset by unused losses from us carried over from prior years, but not by losses from other passive activities, including losses from other publicly traded partnerships.

Further, in addition to the other limitations described above, non-corporate taxpayers may only deduct business losses up to the gross income or gain attributable to such trade or business plus $250,000 ($500,000 for unitholders filing jointly). Amounts that may not be deducted in a taxable year may be carried forward into the following taxable year. This limitation shall be applied after the passive loss limitations and, unless amended, applies only to taxable years beginning prior to December 31, 2025.

Our ability to deduct business interest is limited under the TCJA and is expected to increase our taxable income allocable to our unitholders.

Our ability to deduct interest on indebtedness properly allocable to our trade or business (which excludes investment interest) will be limited to an amount equal to the sum of (i) our business interest income during the taxable year and (ii) 30% of our adjusted taxable income for such taxable year. Disallowed interest deductions will be allocated to our unitholders and will be available to offset our future excess taxable income allocated to such unitholders. A unitholder’s tax basis in our interests will be reduced by the amount of disallowed interest deductions allocated to such unitholder, even if such amounts do not give rise to a deduction to the unitholder in that taxable year. Such unitholder’s tax basis in its partnership interests will be subsequently increased immediately prior to any disposition by such unitholder of its interest in us in an amount equal to the difference between the prior basis reduction and the amount of the disallowed interest that has subsequently been used to offset excess taxable income of the unitholder.

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The limitation on the deductibility of business interest expense described above also applies to our corporate subsidiaries; however, disallowed interest deductions will be carried forward by our corporate subsidiaries and treated as business interest paid or accrued in the succeeding taxable year. The deductibility of such business interest expense carried forward from a prior taxable year will be subject to the limitation described above.

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 that 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.

If the IRS makes audit adjustments to our income tax returns for tax years beginning after 2017, it may collect any resulting taxes (including any applicable penalties and interest) directly from us, in which case our cash available for distribution to our unitholders might be substantially reduced.

If the IRS makes audit adjustments to income tax returns for tax years beginning after 2017, it may assess and collect taxes (including any applicable penalties and interest) directly from us in the year in which the audit is completed. If we are required to make payments of taxes, penalties and interest resulting from audit adjustments, our cash available for distribution to our unitholders might be substantially reduced. In addition, because payment would be due for the taxable year in which the audit is completed, unitholders during that taxable year would bear the expense of the adjustment even if they were not unitholders during the audited taxable year.

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

Investment in our units by tax-exempt entities, such as individual retirement accounts (known as IRAs), pension plans 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 U.S. 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.

Pursuant to the TCJA, if a non-U.S. unitholder sells or otherwise disposes of a common unit, the transferee is required to withhold 10% of the amount realized by the non-U.S. transferor, and we are required to deduct and withhold from distributions to the transferee amounts that should have been withheld by the transferee but were not withheld. However, the U.S. Department of the Treasury and the IRS have determined that this withholding requirement should not apply to any disposition of a publicly traded interest in a publicly traded partnership (such as us) until regulations or other guidance have been issued clarifying the application of this withholding requirement to dispositions of interests in publicly traded partnerships. Accordingly, while this new withholding requirement does not currently apply to interests in us, there can be no assurance that such requirement will not apply in the future.

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.

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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 several states, most of which currently impose income taxes on corporations, and many of which 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, local and foreign tax returns. Under the tax laws of some states where we 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 obtain a withholding exemption affidavit from and generally report detailed tax information about our non-Oklahoma resident unitholders 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.

We hold certain assets located at certain of our liquid asphalt facilities in 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 hold certain of our liquid asphalt processing assets and related fee income through BKEP Asphalt, L.L.C., 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 21%, 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. Currently, the maximum federal income tax rate applicable to dividend income from such subsidiary which is allocable to individuals is 20% plus an unearned Medicare tax of 3.8%. An individual unitholder's share of dividend and interest income from such subsidiary would constitute portfolio income which could not be offset by the unitholder's share of our other losses or deductions. If a material amount of entity-level taxes is incurred by such subsidiary, then our cash available for distribution to our 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. The U.S. Department of the Treasury and the IRS issued final Treasury regulations pursuant to which a publicly traded partnership may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders, although such tax items must be prorated on a daily basis. However, these Treasury regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to successfully challenge our proration method, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A unitholder whose units are loaned to a “short seller” to 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. 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 to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

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Unitholders converting Preferred Units into common units 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 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 to 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.

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. For example, from time to time, the President and members of Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships, including elimination of partnership tax treatment for publicly traded partnerships. Any modification to the federal income tax laws and interpretations thereof may or may not be retroactively applied and could make it more difficult or impossible for us to meet the requirements that must be satisfied in order for us to be treated as a partnership for federal income tax purposes.

We are unable to predict whether any of these changes, or other proposals, will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units. Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner which subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal income tax purposes, the minimum quarterly distribution and the target distribution levels will be adjusted to reflect the impact of that law on us.

On January 24, 2017, the U.S. Department of the Treasury and the IRS published final regulations (the "Final Regulations") regarding qualifying income under Section 7704(d)(1)(E) of the Code. The Final Regulations provide guidance on the activities that generate qualifying income. In addition, under special transition rules, publicly traded partnerships are permitted to treat income from certain activities that the partnership engaged in prior to May 6, 2015, and that would not otherwise be considered to generate qualifying income under the Final Regulations, as qualifying income for 10 years. Under the Final Regulations, income we realize from the blending and storage of asphalt emulsions and certain types of polymer modified asphalt products, which we have historically treated as generating qualifying income, might be considered to no longer constitute qualifying income. Moreover, we may not be able to apply the special transition rules with respect to a portion of such income. In such cases, we may determine to transfer part of the assets that are used to generate such income, as well as the income itself, to a subsidiary taxed as a corporation. Any such subsidiary would be 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.

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We may adopt certain valuation methodologies and monthly conventions for federal income tax purposes that may result in a shift of income, gain, loss or 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 or 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 or 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.

Compliance with and changes in tax law could adversely affect our performance.

We are subject to extensive tax laws and regulations, including federal and state income taxes and transactional taxes such as excise, sales/use, payroll, franchise and ad valorem taxes. New tax laws and regulations and changes in existing tax laws and regulations are continuously being enacted that could result in increased tax expenditures in the future. Many of these tax liabilities are subject to audits by the respective taxing authority. These audits may result in additional taxes as well as interest and penalties.

Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties.

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

Title to Properties

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.

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 which have not been subordinated to the right-of-way grants. We have also obtained, where necessary, easement agreements, licenses or permits 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 the event of a challenge to our pipeline location, we generally have the right of eminent domain or other recourse to retain the pipeline in place. 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.

Other than as described above, we believe that we have satisfactory title to or rights in all of our assets. Although title or rights 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.

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Item 3. Legal Proceedings.

The information required by this item is included under the caption "Commitments and Contingencies" in Note 17 to our consolidated financial statements and is incorporated herein by reference thereto.

Item 4. Mine Safety Disclosures.

Not applicable.

PART II. OTHER INFORMATION

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

Our common units are traded on the Nasdaq Global Market under the symbol "BKEP" and our Preferred Units are traded on the Nasdaq Global Market under the symbol "BKEPP".

On March 1, 2018, there were 40,310,272 common units outstanding, held by approximately 904 unitholders of record and 35,125,202 Preferred Units outstanding held by approximately 3 unitholders of record. The actual number of unitholders is greater than the number of holders of record. Ergon holds 7.6% of the common units and 52.1% of the Preferred Units.

The following table shows the high and low sales prices per common unit and Preferred Unit, as reported by Nasdaq, as well as distributions declared by quarter during the periods indicated.

Common Units	Low	High	Cash Distribution per Unit
2016:			
First Quarter	$3.81	$5.77	$ 0.1450
Second Quarter	4.56	5.61	0.1450
Third Quarter	5.07	6.50	0.1450
Fourth Quarter	5.72	7.00	0.1450
2017:			
First Quarter	$6.55	$7.55	$ 0.1450
Second Quarter	6.17	7.35	0.1450
Third Quarter	5.30	6.45	0.1450
Fourth Quarter	4.65	5.95	0.1450
Preferred Units			
2016:			
First Quarter	$5.71	$7.13	$ 0.17875
Second Quarter	4.56	5.61	0.17875
Third Quarter	6.84	8.75	0.17875
Fourth Quarter	7.60	8.39	0.17875
2017:			
First Quarter	$7.62	$8.20	$ 0.17875
Second Quarter	7.71	8.52	0.17875

Third Quarter	7.28	8.05	0.17875
Fourth Quarter	7.35	7.98	0.17875

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 agreement, we are permitted to make quarterly distributions of available cash to unitholders so long as no default exists under the credit agreement on a pro forma basis after giving effect to such distribution.

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

- first, 98.4% to the holders of Preferred Units, pro rata, and 1.6% to our General Partner, until we distribute for each outstanding Preferred Unit an amount equal to the Series A Quarterly Distribution Amount (as defined in the partnership agreement) for that quarter;
- second, 98.4% to the holders of Preferred Units, pro rata, and 1.6% 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, 98.4% to all common unitholders and Class B unitholders (if any), pro rata, and 1.6% 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 1.6% general partner interest and that we do not issue additional classes of equity securities.

General Partner Interest and Incentive Distribution Rights

The following discussion assumes that our General Partner maintains its approximate 1.6% general partner’s interest and continues to own the incentive distribution rights.

Our partnership agreement provides that our General Partner will be entitled to approximately 1.6% 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 1.6% general partner interest if we issue additional units. Our General Partner’s approximate 1.6% 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.

Incentive distribution rights represent the right to receive an increasing percentage (13.0%, 23.0% and 48.0%) 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.

If for any quarter:

- 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, 98.4% to all unitholders holding common units or Class B units, pro rata, and 1.6% to our General Partner, until each unitholder receives a total of $0.1265 per unit for that quarter (the “first target distribution”);
- second, 85.4% to all unitholders holding common units or Class B units, pro rata, and 14.6% to our General Partner, until each unitholder receives a total of $0.1375 per unit for that quarter (the “second target distribution”);
- third, 75.4% to all unitholders holding common units or Class B units, pro rata, and 24.6% to our General Partner, until each unitholder receives a total of $0.1825 per unit for that quarter (the “third target distribution”); and
- thereafter, 50.4% to all unitholders holding common units or Class B units, pro rata, and 49.6% 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 annual periods and as of the dates presented.

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.”

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	2013	2014	2015	2016	2017
Statements of Operations Data:	(in thousands, except for per unit data)				
Service revenue:					
Third-party revenue	$142,916	$139,426	$137,415	$126,215	$113,772
Related-party revenue[(1)]	51,755	42,788	39,103	30,211	56,688
Product sales revenue:					
Third-party revenue	—	4,412	3,511	20,968	11,479
Total revenue	194,671	186,626	180,029	177,394	181,939
Costs and expenses:					
Operating expense	133,610	134,184	127,974	111,091	123,805
Cost of product sales	—	61	3,231	14,130	8,807
General and administrative expense	17,482	17,498	18,976	20,029	17,112
Asset impairment expense	524	—	21,996	25,761	2,400
Total costs and expenses	151,616	151,743	172,177	171,011	152,124
Gain (loss) on sale of assets	1,073	2,464	6,137	108	(975)
Operating income	44,128	37,347	13,989	6,491	28,840
Other income (expense):					
Equity earnings (loss) in unconsolidated entity	(502)	883	3,932	1,483	61
Gain on sale of unconsolidated affiliate	—	—	—	—	5,337
Interest expense	(11,615)	(12,268)	(11,202)	(12,554)	(14,027)
Unrealized gain on investments	—	2,079	—	—	—
Income (loss) before income taxes	32,011	28,041	6,719	(4,580)	20,211
Provision for income taxes	593	469	323	260	166
Net income (loss) from continuing operations	31,418	27,572	6,396	(4,840)	20,045
Loss from discontinued operations	(3,383)	—	—	—	—
Net income (loss)	$28,035	$27,572	$6,396	$(4,840)	$20,045
Allocation of net income (loss) for purpose of calculating earnings per unit:					
General partner interest in net income	$647	$641	$554	$433	$944
Preferred interest in net income	$21,564	$21,563	$21,564	$25,824	$25,115
Net income (loss) available to limited partners	$5,824	$5,368	$(15,722)	$(31,097)	$(6,014)
Basic and diluted net income (loss) per common unit	$0.25	$0.20	$(0.47)	$(0.87)	$(0.15)
Cash distributions per unit to limited partners[(2)]:					
Paid	$0.48	$0.52	$0.56	$0.58	$0.58
Declared	$0.49	$0.53	$0.57	$0.58	$0.58
Cash distributions per unit to preferred partners:					
Paid	$0.72	$0.72	$0.72	$0.72	$0.72
Declared	$0.72	$0.72	$0.72	$0.72	$0.72
Balance Sheet Data (at period end):					
Property, plant and equipment, net	$297,400	$310,163	$312,934	$307,334	$296,069
Total assets	$354,748	$364,395	$364,746	$375,663	$340,869
Long-term debt and other long-term liabilities	$275,707	$219,736	$247,548	$329,546	$312,542
Total partners' capital	$55,458	$119,956	$87,219	$25,576	$4,684

(1) For the years ended December 31, 2013, 2014, 2015, 2016 and 2017, we recognized revenues of $51.2 million, $41.8 million, $37.8 million, $23.2 million and $21.5 million, respectively, for services provided to Vitol. Of these

amounts, $5.3 million and $21.5 million are classified as third-party revenues for the years ended December 31, 2016 and 2017, respectively, while all other amounts are classified as related-party revenues. For the years ended December 31, 2013, 2014, 2015, 2016 and 2017, we recognized revenues of $15.5 million, $15.3 million, $15.5 million, $22.2 million and $56.4 million, respectively, for services provided to Ergon. In the years ended December 31, 2016 and 2017, $10.9 million and $56.4 million, respectively, in revenue for services provided to Ergon subsequent to the Ergon Change of Control (as previously defined) are classified as related-party revenue, while all other amounts are classified as third-party revenues.

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(2) 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 27 states. We provide integrated terminalling, gathering and transportation services for companies engaged in the production, distribution and marketing of liquid asphalt and crude oil. We manage our operations through four operating segments: (i) asphalt terminalling services, (ii) crude oil terminalling services, (iii) crude oil pipeline services and (iv) crude oil trucking and producer field services.

Potential Impact of Crude Oil Market Price Changes and Other Factors on Future Revenues

Since June of 2014, the market price of West Texas Intermediate crude oil has fluctuated significantly from a peak of approximately $108 per barrel to a low of approximately $30 per barrel (as of March 1, 2018, the price per barrel was approximately $63). Furthermore, during the fourth quarter of 2014, the West Texas Intermediate crude oil forward price curve changed from a backwardated curve (in which the current crude oil price per barrel is higher than the future price per barrel and a premium is placed on delivering product to market and selling as soon as possible) to a contango curve (in which future prices are higher than current prices and a premium is placed on storing product and selling at a later time). As of December 31, 2017, the forward price curve is slightly backwardated. In addition to changes in the price of crude oil and changes in the forward pricing curve, there has been significant volatility in the overall energy industry and specifically in publicly traded midstream energy partnerships. As a result there are a number of trends that may impact our partnership in the near term. These include the overall market price for crude oil and whether or not the forward price curve is in contango or backwardated, changes in production and the demand for transportation capacity in the areas in which we serve, and overall changes in our cost of capital. We expect this volatility to have near-term impacts as discussed below.

Asphalt Terminalling Services - Although there is no direct correlation between the price of crude oil and the price of asphalt, the asphalt industry tends to benefit from a lower crude oil price environment, strong economy and an increase in infrastructure spend. As a result, we do not expect the changes in the price of crude oil to significantly impact our asphalt terminalling services operating segment.

Crude Oil Terminalling Services - A contango crude oil curve tends to favor the crude oil storage business as crude oil marketers are incentivized to store crude oil during the current month and sell into a future month. As a result of the decrease in the crude oil price and change in the crude oil futures pricing curve, our weighted average storage rates increased from September 2014 to March 2016. Since March of 2016, the crude oil curve has generally been in a shallow contango, meaning the current price of oil is only slightly less than the price in future months. In these shallow contango markets there is no clear incentive for marketers to store barrels. As of December 31, 2017, the forward price curve is slightly backwardated. In addition, a shallow contango or a backwardated market may impact our ability to re-contract expiring contracts and/or decrease the storage rate at which we are able to re-contract.

Crude Oil Pipeline Services - In late April 2016, as a precautionary measure, we suspended service on a segment of our Mid-Continent pipeline system due to a discovery of a pipeline exposure caused by heavy rains and the erosion of a riverbed in southern Oklahoma. There was no damage to the pipeline and no loss of product. In the second quarter of 2016, we took action to mitigate the service suspension and worked with customers to divert volumes, and, in certain circumstances, transported volumes to a third-party pipeline system via truck. In addition, the term of the throughput and deficiency agreement on our Eagle North pipeline system expired at June 30, 2016, and, in July of 2016, we completed a connection of the southeastern most portion of our Mid-Continent pipeline system to our Eagle North pipeline system and concurrently reversed the Eagle North pipeline system.

We are currently operating one Oklahoma mainline system, which is a combination of both the Mid-Continent and Eagle North pipeline systems instead of two separate systems, providing us with a current capacity of approximately 20,000 to 25,000 Bpd. We are working to restore service of the second Oklahoma pipeline system and expect to put the line back in service by the end of the second quarter of 2018, increasing the transportation capacity of our pipeline systems by approximately 20,000 Bpd. The ability to fully utilize the capacity of these systems may be impacted by the market price of crude oil and producers’ decisions to increase or decrease production in the areas we serve.

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We experienced a decrease in revenue on our East Texas pipeline system as a result of an overall decrease in production in the area and the expiration of an incentive tariff on a section of the system in 2015. As a result of the decrease in revenues and resulting decline in market values, we recognized non-cash impairment expenses of $12.6 million and $1.4 million related to our East Texas pipeline system and a portion of our Mid-Continent pipeline system, respectively, in the fourth quarter of 2015 and an additional $2.3 million related to our East Texas pipeline system in the fourth quarter of 2016. On April 18, 2017, we sold the East Texas pipeline system. We received cash proceeds at closing of approximately $4.8 million and recorded a gain of less than $0.1 million.

The Knight Warrior project was canceled during the second quarter of 2016 due to continued low rig counts in the Eaglebine/Woodbine area coupled with lower production volumes, competing projects and the overall impact of the decreased market price of crude oil. Consequently, shipper commitments related to the project were cancelled, and an impairment expense of $22.6 million related to the project was recognized in June 2016.

On April 3, 2017, Advantage Pipeline, L.L.C. ("Advantage Pipeline"), in which we owned an approximate 30% equity ownership interest, was acquired by a joint venture formed by affiliates of Plains All American Pipeline, L.P. and Noble Midstream Partners LP. We received cash proceeds at closing from the sale of our approximate 30% equity ownership interest in Advantage Pipeline of approximately $25.3 million and recorded a gain on the sale of the investment of $4.2 million. Approximately 10% of the gross sale proceeds were held in escrow, subject to certain post-closing settlement terms and conditions. We received approximately $1.1 million of the funds held in escrow in August 2017 and our remaining balance of $2.2 million in January 2018.

Crude Oil Trucking and Producer Field Services - A backwardated crude oil curve tends to favor the crude oil transportation services business as crude oil marketers are incentivized to deliver crude oil to market and sell as soon as possible. When the crude oil market curve changed from a backwardated curve to a contango curve in the fourth quarter of 2014, coupled with a decrease in the absolute price of crude oil, transported volumes started decreasing. Throughout 2015, we experienced downward rate pressure in our trucking and producer field services business as producers and marketers attempted to renegotiate service rates to preserve their operating margins in the changing market. In addition, during the second half of 2015, our West Texas operating margins and transported volumes were negatively impacted by increased competition from transporters moving equipment from crude oil shale areas to West Texas, where crude oil volumes have remained relatively consistent, and by producers and marketers quickly pipe-connecting transported barrels. As a result, we decided to cease trucking barrels in West Texas in the fourth quarter of 2015 and refocus our efforts on transporting barrels around our owned crude oil pipelines and storage assets in Oklahoma and Kansas. In the fourth quarter of 2015, we recorded a restructuring charge of $1.6 million associated with our exit from West Texas in addition to a non-cash impairment expense of $0.5 million associated with a write-down of assets to their estimated net realizable value. See Note 6 to our consolidated financial statements for additional detail regarding this restructuring expense. In addition, in December 2017, we evaluated our producer field services business for impairment and recognized an impairment expense of $2.4 million to record our assets at their estimated fair value.

Recent Events

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

- On March 7, 2018, we acquired an asphalt terminalling facility located in Oklahoma from a third party for $22.0 million.
- On December 1, 2017, we consummated a Purchase & Sale Agreement, dated as of November 22, 2017, among us and Ergon Asphalt & Emulsions, Inc. and Ergon Terminaling, Inc., both subsidiaries of Ergon, Inc., relating to the acquisition of an asphalt terminalling facility located in Bainbridge, Georgia, from Ergon Asphalt & Emulsions, Inc. and Ergon Terminaling, Inc. for a total purchase price of $10.2 million, consisting of 1,898,380 common units

representing limited partner interests in us.

- On May 11, 2017, we entered into an amended and restated credit agreement that consists of a $450.0 million revolving loan facility.
- On April 18, 2017, we sold the East Texas pipeline system. We received cash proceeds at closing of approximately $4.8 million and recorded a gain of less than $0.1 million.
- April 3, 2017, Advantage Pipeline was acquired by a joint venture formed by affiliates of Plains All American Pipeline, L.P. and Noble Midstream Partners LP. We received cash proceeds at closing from the sale of our approximate 30% equity ownership interest in Advantage Pipeline of approximately $25.3 million and recorded a gain on the sale of the investment of $4.2 million. Approximately 10% of the gross sale proceeds were held in escrow, subject to certain post-closing settlement terms and conditions. We received approximately $1.1 million of the funds held in escrow in August 2017 and our remaining balance of $2.2 million in January 2018.

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- October 5, 2016 - We completed the Ergon Transactions which consisted of the following transactions and agreements:
Ergon purchased 100% of the outstanding voting stock of Blueknight GP Holding, L.L.C., which owns 100% of the capital stock of our General Partner, pursuant to a Membership Interest Purchase Agreement dated July 19, 2016, among CBB, an indirect wholly-owned subsidiary of Charlesbank, BEHI, an indirect wholly-owned subsidiary of Vitol, and Ergon Asphalt Holdings, LLC, a wholly-owned subsidiary of Ergon (the previously defined Ergon Change of Control);
Ergon contributed nine asphalt terminals plus $22.1 million in cash in return for total consideration of approximately $144.7 million, which consisted of the issuance of 18,312,968 of Preferred Units in a private placement;
we repurchased 6,667,695 Preferred Units from each of Vitol and Charlesbank in a private placement for an aggregate purchase price of approximately $95.3 million. Vitol and Charlesbank each retained 2,488,789 Preferred Units upon completion of these transactions;
Ergon acquired an aggregate of $5.0 million of common units for cash in a private placement, pursuant to a Contribution Agreement between us, Blueknight Terminal Holding, L.L.C., and three indirect wholly-owned subsidiaries of Ergon;
we and Ergon entered into the Storage, Throughput and Handling Agreement under which we operate certain asphalt terminals, storage tanks and related real property, contracts, permits, and related assets previously owned by Ergon, and we store and terminal Ergon's asphalt products in exchange for the payment of certain fees by Ergon. The term of the agreement began on October 5, 2016 and will continue for a period of seven years. The agreement will then continue on a year-to-year basis unless cancelled by either party by delivering not less than 180 days' notice; and
we entered into the Omnibus Agreement, dated October 5, 2016 (the "Omnibus Agreement"), with Ergon pursuant to which Ergon was granted a right of first offer with respect to the (i) Wolcott, Kansas Asphalt Terminal; (ii) Ennis, Texas Asphalt Terminal; (iii) Chandler, Arizona Asphalt/Emulsion Terminal; (iv) Mt. Pleasant, Texas Emulsion Terminal; (v) Pleasanton, Texas Emulsion Terminal; (vi) Birmingport, Alabama Asphalt/Polymer/Emulsion Terminal; (vii) Memphis, Tennessee Asphalt/Polymer/Emulsion Terminal; (viii) Nashville, Tennessee Asphalt/Polymer Terminal; (ix) Yellow Creek, Mississippi Asphalt Terminal; (x) Fontana, California Asphalt/Emulsion Terminal; and (xi) Las Vegas, Nevada Asphalt/Emulsion/Polymer Terminal (collectively, the "ROFO Assets") to the extent that we, as the owner of the ROFO Assets, proposes to transfer such ROFO Asset while the Omnibus Agreement is in effect. In addition, the Omnibus Agreement also granted Ergon a right of first refusal to purchase the (i) Fontana, California Asphalt/Emulsion Terminal and (ii) Las Vegas, Nevada Asphalt/Emulsion/Polymer Terminal (together, the "ROFR Assets") if any owner of the ROFR Assets proposes or intends to sell any ROFR Asset to a third party through the period ending December 31, 2018.
- July 26, 2016 - We issued and sold 3,795,000 common units for a public offering price of $5.90 per unit, resulting in proceeds of approximately $21.2 million, net of underwriters' discount and offering expenses of $1.5 million.
- July 19, 2016 - We entered into a Second Amendment to Amended and Restated Credit Agreement (the "Credit Agreement Amendment"), which amended the Amended and Restated Credit Agreement, dated as of June 28, 2013, with Wells Fargo Bank, National Association as administrative agent and the several lenders from time to time party thereto.
- June 2016 - We evaluated the prospects of Knight Warrior, a previously announced East Texas Eaglebine/Woodbine crude oil pipeline project, and decided to not pursue development of the project due to continued low rig counts in the Eaglebine/Woodbine area coupled with lower production volumes, competing projects and the overall impact of the decreased market price of crude oil. Consequently, shipper commitments related to the project were canceled, and an impairment expense of $22.6 million related to the project was recognized in June 2016.

Our Revenues

Our revenues consist of (i) terminalling revenues, (ii) gathering, transportation and producer field services revenues, (iii) product sales revenues, and (iv) fuel surcharge revenues. On October 5, 2016, Ergon acquired 100% of the outstanding voting stock of our General Partner from Vitol and Charlesbank. Beginning on October 5, 2016, revenue from services provided to Ergon is presented as related-party revenue and revenue from services provided to Vitol is presented as a third-party revenue. During the year ended December 31, 2017, we derived approximately $56.7 million of our revenues from services we provided to related parties, with $56.4 million and $0.3 million attributable to Ergon and Advantage Pipeline, respectively.

Terminalling revenues consist of (i) 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 (ii) 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 or 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 revenues in two of our segments: (i) crude oil terminalling services and (ii) asphalt terminalling services.

As of March 1, 2018, we have approximately 5.4 million barrels of crude oil storage under service contracts, including 4.7 million barrels of crude oil storage contracts that are either month-to-month contracts or expire in 2018. The weighted average remaining term on the service contracts is approximately 11 months, with one contract having a remaining term of 47 months. Storage contracts with Vitol represent 2.2 million barrels of crude oil storage capacity under contract.

As of March 7, 2018, we have leases and terminalling agreements for all of our 56 asphalt facilities, including 26 facilities under contract with Ergon. Lease and terminalling agreements related to 16 of these facilities have terms that expire by the end of 2018, while the agreements relating to our additional 40 facilities have on average five years remaining under their terms. We operate the asphalt facilities pursuant to terminalling agreements while our contract counterparties operate the asphalt facilities that are subject to 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 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 year ended December 31, 2017, we transported approximately 23,000 Bpd on our pipelines, a decrease of 36% as compared to the year ended December 31, 2016. The decrease in volumes is primarily attributable to suspended service on our Mid-Continent pipeline system due to a discovery of a pipeline exposure in April 2016. We are working to restore service of the second Oklahoma pipeline system and expect to put the line back in service by the end of the second quarter of 2018, increasing the transportation capacity of our pipeline systems by approximately 20,000 Bpd. See Crude oil pipeline services within our results of operations discussion for additional detail. Vitol accounted for 57% and 33% of volumes transported in 2017 and 2016, respectively.

During the year ended December 31, 2017, we transported approximately 21,000 Bpd on our crude transport trucks, a decrease of 22% as compared to the year ended December 31, 2016. As noted above, we are working to restore service of the second Oklahoma pipeline system and expect to put the line back in service by the end of the second quarter of 2018. When our second Oklahoma pipeline system resumes service, we anticipate an increase in volumes transported by our crude oil transport trucks as we gather barrels to be transported on this pipeline. See Crude oil trucking and producer field services within our results of operations discussion for additional detail. Vitol accounted for approximately 43% and 30% of volumes transported in 2017 and 2016, respectively.

Product sales revenues are comprised of (i) revenues recognized for the sale of crude oil to our customers that we purchase at production leases and (ii) revenue recognized in buy/sell transactions with our customers. Product sales revenue is recognized for products upon delivery and when the customer assumes the risks and rewards of ownership. We earn product sales revenue in our crude oil pipeline services operating segment.

Fuel surcharge revenues are comprised of revenues recognized for the reimbursement of fuel and power consumed to operate our asphalt 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 11% in 2017 as compared to 2016. This increase is primarily attributable to the acquisition of the nine asphalt terminals from Ergon in October 2016. General and administrative expenses decreased by 15% in 2017 as compared to 2016. This decrease is primarily attributable to expenses incurred in 2016 related to the Ergon Transactions. Our interest expense increased by $1.5 million in 2017 as compared to 2016. See Interest expense within our results of operations discussion for additional detail regarding the factors that contributed to the increase in interest expense in 2017.

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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 sheets. 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 statements 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.

Based on the consideration of the above factors for our subsidiary that is taxed as a corporation 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, 2017.

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 of liquid asphalt and crude oil. Our operations have minimal direct exposure to changes in liquid asphalt and crude oil prices, but the volumes of liquid asphalt and crude oil we terminal, gather or transport are 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 of liquid asphalt and crude oil.

- Asphalt Terminalling Services. Our 56 asphalt terminals are located in 26 states and are well-positioned to provide asphalt terminalling services in the market areas they serve throughout the continental United States. With our approximately 10.3 million barrels of total liquid asphalt storage capacity, we are able to provide our customers the ability to effectively manage their liquid asphalt inventories while allowing significant flexibility in their processing and marketing activities. We currently have terminalling contracts or leases with customers for all of our 56 asphalt facilities.
- Crude oil terminalling assets and services. We provide crude oil terminalling services at our terminalling facility located in Oklahoma. We currently own and operate approximately 6.6 million barrels of storage capacity 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 terminal has the capacity to receive or deliver approximately 10.0 million barrels of crude oil per month. We also own approximately 50 acres of additional land within the Cushing Interchange where we can develop additional storage capacity.

- Crude oil pipeline assets and services. We currently own and operate one pipeline system. Our Mid-Continent pipeline system, which is located in Oklahoma and the Texas Panhandle, consists of a combined length of approximately 655 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 facilities owned by us and others. We previously owned and operated the East Texas pipeline system, which is located in Texas. On April 18, 2017, we sold the East Texas pipeline system. See Note 7 of our Consolidated Financial Statements for additional information.

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- Crude oil trucking and producer field services. In addition to our pipelines, we use our approximately 65 owned or leased tanker trucks to gather crude oil in Oklahoma, Kansas and Texas 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. Our producer service fleet consists of approximately 85 trucks in a number of different sizes.

Factors That Will Significantly Affect Our Results

Commodity Prices. Although our current operations have minimal direct exposure to commodity prices, the volumes of liquid asphalt and crude oil we terminal, gather or transport are 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 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 liquid asphalt we terminal and crude oil we terminal, gather and transport. 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 terminal facilities will have a corresponding effect on the volumes we terminal, gather or transport. The production and demand for liquid asphalt and crude oil are driven by many factors, including the price of 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 ultimately 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.

Vitol Storage Agreements

In recent years, a significant portion of our crude oil storage capacity has been dedicated to Vitol under multiple agreements. As of December 31, 2015, 2016 and 2017, 2.2 million barrels of storage capacity were dedicated to Vitol under these storage agreements. Service revenues under these agreements are based on the barrels of storage dedicated to Vitol under the applicable agreement at rates that, we believe, 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 in accordance with our procedures for approval of related-party transactions and the provisions of the partnership agreement. For the year ended December 31, 2015, we generated revenues under these agreements of approximately $9.4 million, all of which is classified as related-party revenue. For the year ended December 31, 2016, we generated revenues under these agreements of approximately $9.6 million, of which $2.1 million was classified as third-party revenue. All revenue for 2017 is classified as third-party revenue.

As of March 1, 2018, 2.2 million barrels of storage capacity were dedicated to Vitol under the crude oil storage agreement with the current term scheduled to expire on April 30, 2018. We are in the process of renegotiating this contract, however, we may not be able to extend, renegotiate or replace this contract when it expires and the terms of any renegotiated contracts may not be as favorable as the contracts they replace.

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Ergon Agreements

Twenty-six of our asphalt terminals are contracted to Ergon under multiple agreements. Service revenues under these agreements are primarily based on contracted monthly fees under the applicable agreement at rates, which we believe are fair and reasonable to us and our unitholders and are comparable with the rates we charge third parties. As of March 7, 2018, leases and storage agreements related to 15 of these facilities are scheduled to expire by the end of 2018. 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. The Board’s conflicts committee reviewed and approved these agreements in accordance with our procedures for approval of related-party transactions and the provisions of the partnership agreement. For the year ended December 31, 2015, we recognized revenues of $15.5 million for services provided to Ergon under these agreements, all of which is classified as third-party revenue. For the year ended December 31, 2016, we recognized revenues of $22.1 million for services provided to Ergon under these agreements, of which $10.9 million is classified as related-party revenue. For the year ended December 31, 2017, we recognized revenues of $56.3 million for services provided to Ergon under these agreements, all of which is classified as related-party revenue.

Results of Operations

Non-GAAP Financial Measures

To supplement our financial information presented in accordance with GAAP, management uses additional measures that are known as “non-GAAP financial measures” in its evaluation of past performance and prospects for the future. The primary measure used by management is operating margin excluding depreciation and amortization.

Management believes that the presentation of such additional financial measures provides useful information to investors regarding our performance and results of operations because these measures, when used in conjunction with related GAAP financial measures, (i) provide additional information about our core operating performance and ability to generate and distribute cash flow; (ii) provide investors with the financial analytical framework upon which management bases financial, operational, compensation and planning decisions; and (iii) present measurements that investors, rating agencies and debt holders have indicated are useful in assessing us and our results of operations. These additional financial measures are reconciled to the most directly comparable measures as reported in accordance with GAAP, and should be viewed in addition to, and not in lieu of, our consolidated financial statements and footnotes.

The table below summarizes our financial results for the years ended December 31, 2015, 2016 and 2017, reconciled to the most directly comparable GAAP measure:

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Operating Results (dollars in thousands)	Year ended December 31, 2015	2016	2017	Favorable/(Unfavorable) 2015-2016 $	%	2016-2017 $	%
Operating margin, excluding depreciation and amortization							
Asphalt terminalling services operating margin	$48,212	$56,769	$64,623	$8,557	18 %	$7,854	14 %
Crude oil terminalling services operating margin	18,842	20,048	17,977	1,206	6 %	(2,071)	(10)%
Crude oil pipeline services operating margin	7,694	4,347	(1,700)	(3,347)	(44)%	(6,047)	(139)%
Crude oil trucking and producer field services operating margin	1,304	1,829	(434)	525	40 %	(2,263)	(124)%
Total operating margin, excluding depreciation and amortization	76,052	82,993	80,466	6,941	9 %	(2,527)	(3)%
Depreciation and amortization	27,228	30,820	31,139	(3,592)	(13)%	(319)	(1)%
General and administrative expense	18,976	20,029	17,112	(1,053)	(6)%	2,917	15 %
Asset impairment expense	21,996	25,761	2,400	(3,765)	(17)%	23,361	91 %
Gain (loss) on sale of assets	6,137	108	(975)	(6,029)	(98)%	(1,083)	(1,003)%
Operating income	13,989	6,491	28,840	(7,498)	(54)%	22,349	344 %
Other income (expense):							
Equity earnings in unconsolidated affiliate	3,932	1,483	61	(2,449)	(62)%	(1,422)	(96)%
Gain on sale of unconsolidated affiliate	—	—	5,337	—	N/A	5,337	N/A
Interest expense	(11,202)	(12,554)	(14,027)	(1,352)	(12)%	(1,473)	(12)%
Provision for income taxes	(323)	(260)	(166)	63	20 %	94	36 %
Net income (loss)	$6,396	$(4,840)	$20,045	$(11,236)	(176)%	$24,885	514 %

Total operating margin excluding depreciation and amortization decreased 3% from 2016 to 2017. Asphalt terminalling services operating margin increased $7.9 million or 14% from 2016 to 2017 as a result of the acquisition of eleven asphalt terminals in 2016, increased product throughput volumes and renegotiated throughput fees for some of our asphalt facilities. This increase was partially offset by decreases in our other operating segments. The decrease in our crude oil terminalling services operating margin was primarily due to decreased throughput fees as lower volumes were transferred in and out of our facilities, coupled with lower re-contracted storage rates as prior contracts expired throughout the year. The crude oil pipeline services operating margin decreased primarily due to a decrease in volume transported by our pipelines related to suspended service on our Mid-Continent pipeline system beginning in April 2016 after a discovery of a pipeline exposure caused by heavy rains and erosion of a river in southern Oklahoma, as well as the sale of our East Texas pipeline system in April 2017.

Total operating margin excluding depreciation and amortization increased 9% from 2015 to 2016. Asphalt terminalling services operating margin increased $8.6 million or 18% from 2015 to 2016 as a result of the acquisition of eleven asphalt terminals in 2016, increased product throughput volumes and renegotiated throughput fees for some of our asphalt facilities. This increase was partially offset by decreases in our crude oil pipeline services operating segment, primarily due to a decrease in volume transported by our pipelines related to suspended service on our Mid-Continent pipeline system beginning in April 2016 after a discovery of a pipeline exposure caused by heavy rains and erosion of a river in southern Oklahoma.

A more detailed analysis of changes in operating margin by segment follows.

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Analysis of Operating Segments

Asphalt terminalling services segment

Our asphalt terminalling services segment operations generally consist of fee-based activities associated with providing terminalling services, including storage, blending, processing and throughput services, for asphalt product and residual fuel oil. Revenue is generated through short- and long-term storage contracts.

The following table sets forth our operating results from our asphalt terminalling services segment for the periods indicated:

Operating results	Year ended December 31,			Favorable/(Unfavorable) 2015-2016		2016-2017	
(dollars in thousands)	2015	2016	2017	$	%	$	%
Service revenue:							
Third-party revenue	$72,152	$75,655	$57,486	$3,503	5 %	$(18,169)	(24)%
Related-party revenue	1,278	11,762	56,378	10,484	820 %	44,616	379 %
Total revenue	73,430	87,417	113,864	13,987	19 %	26,447	30 %
Operating expense (excluding depreciation and amortization)	25,218	30,648	49,241	(5,430)	(22)%	(18,593)	(61)%
Operating margin (excluding depreciation and amortization)	$48,212	$56,769	$64,623	$8,557	18 %	$7,854	14 %

The following is a discussion of items impacting our asphalt terminalling services segment operating margin for the periods indicated:

- Overall revenues have increased for the year ended December 31, 2017, as compared to the year ended December 31, 2016, primarily due to the acquisition of eleven asphalt terminals in 2016 as well as increased product throughput at our terminals and renegotiated throughput fees for some of our asphalt facilities. Revenues earned from Ergon moved from third-party to related-party due to the Ergon Change of Control, which resulted in all revenues generated from services provided to Ergon after October 5, 2016, being classified as related-party revenues.

- Operating expenses increased in 2017 as compared to 2016 primarily as a result of the acquisitions noted above. In addition, operating expenses for 2017 increased by $2.4 million as compared to 2016 as a result of two facilities that we previously leased to customers converting to facilities we operate under service agreements.

- Third-party revenues increased for the year ended December 31, 2016, as compared to the year ended December 31, 2015, primarily due to the acquisition of two asphalt terminals in February 2016 as well as increased product throughput at our terminals and renegotiated throughput fees for some of our asphalt facilities. Related-party revenues increased due to the acquisition of nine asphalt facilities from Ergon in October 2016 in conjunction with the Ergon Change of Control, which resulted in all revenues generated from services provided to Ergon after October 5, 2016, being classified as related-party revenues.

- Operating expenses increased in 2016 as compared to 2015 as a result of an increase in utilities, compensation and maintenance and repair expense primarily due to the acquisition of the eleven new terminals in 2016.

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Crude oil terminalling services segment

Our terminalling services segment operations generally consist of fee-based activities associated with providing terminalling services, including storage, blending, processing and throughput services, for crude oil. Revenue is generated through short- and long-term storage contracts.

The following table sets forth our operating results from our crude oil terminalling services segment for the periods indicated:

Operating Results (dollars in thousands)	Year ended December 31, 2015	2016	2017	Favorable/(Unfavorable) 2015-2016 $	%	2016-2017 $	%
Service revenue:							
Third-party revenue	$13,076	$16,387	$22,177	$3,311	25 %	$5,790	35 %
Related-party revenue	11,522	7,858	—	(3,664)	(32)%	(7,858)	(100)%
Total revenue	24,598	24,245	22,177	(353)	(1)%	(2,068)	(9)%
Operating expense (excluding depreciation and amortization)	5,756	4,197	4,200	1,559	27 %	(3)	— %
Operating margin (excluding depreciation and amortization)	$18,842	$20,048	$17,977	$1,206	6 %	$(2,071)	(10)%
Average crude oil stored per month at our Cushing terminal (in thousands of barrels)	5,322	5,536	5,413	214	4 %	(123)	(2)%
Average crude oil delivered to our Cushing terminal (in thousands of barrels per day)	117	78	41	(39)	(33)%	(37)	(47)%

The following is a discussion of items impacting our crude oil terminalling services segment operating margin for the periods indicated:

- Total revenues for 2017 have decreased due to a decrease in market rates for short-term, monthly storage contracts and decreased throughput fees as lower volumes were transferred in and out of our facilities.

- Revenues earned from Vitol have moved from related-party to third-party due to the October 2016 Ergon Change of Control. We do not provide crude oil terminalling services to Ergon.

- Overall operating expenses for 2017 were comparable to 2016. Decreases in maintenance and repair expense were offset by an increase in property tax expense.

- Operating expenses for 2016 decreased compared to 2015, primarily as a result of decreases in utilities expense, as well as a decrease in compensation expense due to the cancellation of an operating and maintenance agreement related to Vitol’s crude oil terminal located in Midland, Texas in the third quarter of 2015.

- As of March 1, 2018, we have approximately 5.4 million barrels of crude oil storage under service contracts, including 4.7 million barrels of crude oil storage contracts that are month-to-month or expire in 2018. The weighted average remaining term on the service contracts is approximately 11 months, with one contract having a remaining term of 47 months. Storage contracts with Vitol represent 2.2 million barrels of crude oil storage capacity under contract.

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Crude oil pipeline services

Our crude oil pipeline services segment operations generally consist of fee-based activity associated with transporting crude oil products on pipelines. Revenues are generated primarily through tariffs and other transportation fees.

The following table sets forth our operating results from our crude oil pipeline services segment for the periods indicated:

Operating Results	Year ended December 31,			Favorable/(Unfavorable) 2015-2016		2016-2017	
(dollars in thousands)	2015	2016	2017	$	%	$	%
Service revenue:							
Third-party revenue	$15,148	$8,662	$9,580	$(6,486)	(43)%	$918	11%
Related-party revenue	10,687	5,433	310	(5,254)	(49)%	(5,123)	(94)%
Product sales revenue:							
Third-party revenue	3,511	20,968	11,094	17,457	497%	(9,874)	(47)%
Total revenue	29,346	35,063	20,984	5,717	19%	(14,079)	(40)%
Operating expense (excluding depreciation and amortization)	18,162	15,270	13,310	2,892	16%	1,960	13%
Operating expense (intersegment)	259	890	417	(631)	(244)%	473	53%
Cost of product sales	3,231	14,130	8,807	(10,899)	(337)%	5,323	38%
Cost of product sales (intersegment)	—	426	150	(426)	N/A	276	65%
Operating margin (excluding depreciation and amortization)	$7,694	$4,347	$(1,700)	$(3,347)	(44)%	$(6,047)	(139)%
Average throughput volume (in thousands of barrels per day)							
Mid-Continent	36	27	22	(9)	(25)%	(5)	(19)%
East Texas[(1)]	16	9	3	(7)	(44)%	(6)	(67)%

(1) Average throughput on the East Texas system for 2017 was calculated based on the period of time we operated the system (January 1, 2017 through April 18, 2017).

The following is a discussion of items impacting our crude oil pipeline services segment operating margin for the periods indicated:

- In late April 2016, as a precautionary measure we suspended service on our Mid-Continent pipeline system due to discovery of a pipeline exposure caused by heavy rains and the erosion of a riverbed in southern Oklahoma. There was no damage to the pipe and no loss of product. In the second quarter of 2016, we took action to mitigate the service suspension and worked with customers to divert volumes and, in certain circumstances, transported volumes to a third-party pipeline system via truck. In addition, the term of the throughput and deficiency agreement on our Eagle North pipeline system expired on June 30, 2016, and in July 2016 we completed a connection of the southeastern-most portion of our Mid-Continent pipeline system to our Eagle North pipeline system and concurrently reversed the Eagle North pipeline system. This enabled us to recapture diverted volumes and deliver those barrels to Cushing, Oklahoma. We are currently operating one Oklahoma mainline system, which is a combination of both the Mid-Continent and Eagle North pipeline systems, instead of two separate systems, providing us with a current capacity of approximately 20,000 to 25,000 Bpd. We are working to restore service of the second Oklahoma pipeline system and expect to put the line back in service by the end of the second quarter of 2018, increasing the transportation capacity of our pipeline systems by approximately 20,000 Bpd. The ability to fully utilize the capacity of these systems may be impacted by the market price of crude oil and producers' decisions to increase or decrease production in the areas we serve.

- Service revenues have moved from related-party to third-party due to Ergon’s acquisition of our General Partner in October 2016, at which time Vitol ceased to be a related party.

- Included in product sales revenue for the year ended 2016 is $4.2 million in sales of crude oil arising from accumulated product-loss allowances (“PLA”). Product sales revenue for 2017 included $0.3 million in PLA sales. In

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addition, as a result of one of our third-party customers utilizing a greater percentage of the capacity of our Red River pipeline, product sales revenue and cost of product sales declined from 2016 to 2017, which decreased the volume of marketed barrels of crude oil, for which revenue and costs are both recorded gross. This decrease was offset by an increase in third-party transportation revenue.

- On April 18, 2017, we sold the East Texas pipeline system. We received cash proceeds at closing of approximately $4.8 million and recorded a gain of less than $0.1 million. The sale of the East Texas pipeline system resulted in decreased service revenues of $2.2 million for year ended 2017 as compared to 2016.

- Operating expenses decreased for 2017 by $1.5 million compared to 2016 as a result of the sale of the East Texas pipeline system and by $0.7 million as a result of the sale of our investment in Advantage Pipeline, for which we provided operational and administrative services through August 1, 2017. Offsetting this decrease was a $0.3 million right-of-way settlement incurred in December 2017 related to the pipeline exposure described above.

- Service revenues for 2016 decreased compared to 2015 due to the expiration of an increased tariff that was being charged from June 2014 through May 2015 on certain barrels transported on our East Texas pipeline system under a throughput and deficiency agreement. The tariff returned to a lower rate in June 2015, which decreased the service revenues generated on the East Texas pipeline system by $4.6 million compared to 2015.

- Product sales revenues and cost of product sales for 2016 increased compared to 2015 due to our acquisition of the Red River pipeline in November 2015. In conjunction with our acquisition of the Red River pipeline, we began marketing crude oil that we purchase at production leases. Revenue from this activity is reflected in product sales revenue. In addition to the marketing revenue, we also had $4.2 million in sales of crude oil arising from accumulated product loss allowances in 2016. There were no sales of accumulated pipeline loss allowances during 2015.

- Operating expenses for 2016 decreased compared to 2015 primarily due to decreases in maintenance and repairs.

Crude oil trucking and producer field services

Our crude oil trucking and producer field services segment operations generally consist of fee-based activity associated with transporting crude oil products on trucks. Revenues are generated primarily through transportation fees.

The following table sets forth our operating results from our crude oil trucking and producer field services segment for the periods indicated:

				Favorable/(Unfavorable)			
Operating Results	Year ended December 31,			2015-2016		2016-2017	
(dollars in thousands)	2015	2016	2017	$	%	$	%
Service revenue:							
Third-party revenue	$37,039	$25,511	$24,529	$(11,528)	(31)%	$(982)	(4)%
Related-party revenue	15,616	5,158	—	(10,458)	(67)%	(5,158)	(100)%
Intersegment revenue	259	890	417	631	244 %	(473)	(53)%
Product sales revenue:							
Third-party revenue	—	—	385	—	N/A	385	N/A
Intersegment revenue	—	426	150	426	N/A	(276)	(65)%
Total revenue	52,914	31,985	25,481	(20,929)	(40)%	(6,504)	(20)%
Operating expense (excluding depreciation and amortization)	51,610	30,156	25,915	21,454	42 %	4,241	14 %
	$1,304	$1,829	$(434)	$525	40 %	$(2,263)	(124)%

Operating margin (excluding depreciation and amortization)							
Average volume (in thousands of barrels per day)	51	27	21	(24	) (47)%	(6	) (22)%

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The following is a discussion of items impacting our crude oil trucking and producer field services segment operating margin for the periods indicated:

- Service revenues and operating expenses have decreased as a result of the continued low crude oil price environment and increased competition in the areas we serve. We continue to experience downward rate pressure in our trucking and producer field services business as producers and marketers attempt to renegotiate service rates to preserve their operating margins in the changing market.

- Revenues have moved from related-party to third-party due to Ergon's acquisition of our General Partner in October 2016, at which time Vitol ceased to be a related party. We do not provide crude oil transportation services to Ergon.

- Increases in product sales revenues for 2017 are the result of a crude oil sale in our field services business to a third party. Intersegment product sales revenues for all periods are the result of crude oil sales in our field services business to our crude oil pipeline services segment.

- During the year ended December 31, 2017, we recognized total fixed asset and intangible asset impairment charges of $2.4 million related to the producer field services business.

- During the second half of 2015, our West Texas operating margins and transported volumes were negatively impacted by increased competition from transporters and marketers quickly pipe-connecting transported barrels. As a result, we decided to cease trucking barrels in West Texas and refocus our efforts on transporting barrels around our owned crude oil pipelines and storage assets in Oklahoma and Kansas. We recorded a restructuring expense of $1.6 million related to employee severance and idle equipment costs related to our exit from the West Texas trucking business in 2015. This restructuring led to the improvement in operating margin from 2015 to 2016 despite decreased volumes and rates.

Other Income and Expenses

Depreciation and amortization. Depreciation and amortization increased to $31.1 million for 2017 compared to $30.8 million for 2016 and $27.2 million for 2015. These increases are primarily the result of pipeline and asphalt facility acquisitions made during the past two years.

General and administrative expense. General and administrative expense was $17.1 million for the year ended December 31, 2017, compared to $20.0 million for 2016 and $19.0 million for 2015. The increase in expense for 2016 over 2017 and 2015 is primarily related to $1.8 million of transaction fees related to the Ergon Change of Control and acquisition-related expenses.

Asset impairment expense. During 2017, we recorded fixed asset and intangible asset impairment expense, including an impairment of goodwill, of $2.4 million related to a write-down of our producer field services business to estimated fair value. During 2016, we recorded fixed asset impairment expense of $25.8 million, primarily due to an impairment recognized on the Knight Warrior pipeline project and the East Texas pipeline system. The Knight Warrior pipeline project was canceled due to continued low rig counts in the Eaglebine/Woodbine area coupled with lower production volumes, competing projects and the overall impact of the decreased market price of crude oil. Consequently, shipper commitments related to the project were canceled. During 2015, we recorded fixed asset impairment expenses of $12.6 million, $1.4 million, and $0.5 million related to the write-down of our East Texas pipeline system, a portion of our Mid-Continent pipeline system and our West Texas trucking stations, respectively, to their estimated fair value. In 2015, we also recorded an impairment expense of $7.5 million related to goodwill associated with our pipeline services reporting unit. We used a discounted cash flow model, supplemented by a market approach, to evaluate goodwill and the estimated fair value of assets. Key assumptions in the analysis include the use of an appropriate discount rate, volume and rate forecasts and estimates of operating costs. Due to the imprecise nature of our projections and assumptions, actual results can and often do differ from our estimates. If the assumptions used in our projections and analysis prove to be inaccurate or if the markets in which we operate experience future adverse conditions, we could incur additional impairment charges in the future.

Gain (loss) on sale of assets. Loss on sale of assets was $1.0 million in 2017 compared to gains of $0.1 million and $6.1 million for 2016 and 2015, respectively. Losses for 2017 include $0.4 million related to the disposal of an asphalt tank floor that had to be replaced due to corrosion. Additional losses in 2017 were the result of sales and disposals of surplus, used property and equipment. The gain on sale of assets in 2016 consists of the sale of surplus, used property and equipment. The gain on sale of assets in 2015 includes a $6.0 million gain on the sale of crude oil pipeline linefill and storage tank bottoms related to the settlement of litigation with SemCorp in September 2015.

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Equity earnings in unconsolidated affiliate. The equity earnings are attributable to our former investment in Advantage Pipeline. On April 3, 2017, we sold our investment in Advantage Pipeline and received cash proceeds at closing from the sale of approximately $25.3 million, recognizing a gain on sale of unconsolidated affiliate of $4.2 million. Approximately 10% of the gross sale proceeds were held in escrow, subject to certain post-closing settlement terms and conditions. We received approximately $1.1 million of the funds held in escrow in August 2017, for which we recognized an additional gain on sale of unconsolidated affiliate during the three months ended September 30, 2017. We received approximately $2.2 million for the pro rata portion of the remaining net escrow proceeds in January 2018.

Interest expense. Interest expense was $14.0 million for 2017 compared to $12.6 million and $11.2 million for 2016 and 2015, respectively. Interest expense represents interest on borrowings under our credit agreement, as well as amortization of debt issuance costs and unrealized gains and losses related to the change in fair value of interest rate swaps.

The increase in interest expense from 2016 to 2017 was primarily the result of increases in the weighted average interest rate and in the weighted average debt outstanding during the period. During 2016 and 2017, the weighted average interest rate under the credit agreement was 3.95% and 4.43%, respectively. In addition, we wrote off $0.7 million of debt issuance costs during 2017 due to the amendment of our credit agreement. These increases were partially offset by decreases in interest expense related to our interest rate swap agreements of $1.8 million.

The increase in interest expense from 2015 to 2016 was primarily the result of increases in the weighted average interest rate and in the weighted average debt outstanding during the periods. During 2015 and 2016, the weighted average interest rate under the credit agreement was 3.37% and 3.95%, respectively. In addition, the interest expense resulting from the amortization of debt issuance costs increased by $0.2 million in 2016. These increases were partially offset by decreases in interest expense related to our interest rate swap agreements of $2.1 million.

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 years ended December 31, 2015, 2016 and 2017:

	Year ended December 31,		
	2015	2016	2017
	(in millions)		
Net cash provided by operating activities	$60.5	$52.8	$54.5
Net cash provided by (used in) investing activities	(44.6)	(159.6)	17.1
Net cash provided by (used in) financing activities	(15.6)	107.0	(72.4)

Operating Activities. Net cash provided by operating activities was $54.5 million for the year ended December 31, 2017, as compared to $52.8 million for the year ended December 31, 2016. The increase in cash provided by operating activities is primarily the result of changes in working capital.

Net cash provided by operating activities was $52.8 million for the year ended December 31, 2016, as compared to $60.5 million for the year ended December 31, 2015. The decrease in cash provided by operating activities is primarily the result of changes in working capital and lower net income.

Investing Activities. Net cash provided by investing activities was $17.1 million for the year ended December 31, 2017, as compared to net cash used in investing activities of $159.6 million for the year ended December 31, 2016. Capital expenditures for the year ended December 31, 2017, included maintenance capital expenditures of $7.9 million, net of reimbursable expenditures of $0.8 million, and expansion capital expenditures of $9.4 million, net of reimbursable expenditures of $0.6 million. These expenditures were offset by proceeds from the sale of our investment in Advantage Pipeline, the East Texas pipeline system and other assets of $26.5 million, $4.8 million and $4.5 million, respectively.

Net cash used in investing activities was $159.6 million for the year ended December 31, 2016, as compared to $44.6 million for the year ended December 31, 2015. Capital expenditures for the years ended December 31, 2016, included acquiring nine asphalt terminal facilities from Ergon for $122.6 million, maintenance capital expenditures of $8.7 million, net of reimbursable expenditures of $1.9 million, expansion capital expenditures of $9.4 million and other acquisitions of $19.0 million. These expenditures were partially offset by proceeds from the sale of assets of $2.0 million. Capital expenditures for the year ended December 31, 2015, included maintenance capital expenditures of $7.9 million, net of reimbursable expenditures of $0.5 million, expansion capital expenditures of $33.2 million, primarily related to the Knight Warrior pipeline project, and acquisitions of $21.0 million. These expenditures were partially offset by proceeds from the sale of assets of $14.7 million as well as $2.3 million related to proceeds from the sale of investments in 2015.

Financing Activities. Net cash used in financing activities was $72.4 million for the year ended December 31, 2017. Financing activities for the year ended December 31, 2017, included net payments under our credit agreement of $16.4 million and distributions to unitholders of $49.2 million. In addition, we received proceeds from equity issuances of $0.2 million.

Net cash provided by financing activities was $107.0 million for the year ended December 31, 2016. Financing activities for the year ended December 31, 2016, included net borrowings under our credit agreement of $79.0 million and distributions to unitholders of $47.2 million. In addition, we received proceeds from equity issuances of $26.3 million and repurchased $95.3 million of Preferred Units.

Net cash used in financing activities was $15.6 million for the year ended December 31, 2015. Financing activities for the year ended December 31, 2015, consisted primarily of net borrowings under our credit agreement of $29.0 million and distributions to unitholders of $41.6 million.

Our Liquidity and Capital Resources

Cash flows from operations and borrowings under our credit agreement are our primary sources of liquidity. Our ability to borrow funds under our credit agreement may be limited by financial covenants. At December 31, 2017, we had a working capital deficit of $0.1 million. This is primarily a function of our approach to cash management. At December 31, 2017, we had approximately $140.9 million of availability under our revolving loan facility, and we could borrow up to $317.0 million, or an additional $7.9 million, and still remain within our covenant restrictions. As of March 1, 2018, we have aggregate unused commitments under our revolving loan facility of approximately $139.9 million and cash on hand of approximately $1.3 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 $10.0 million in the year ended December 31, 2017, compared to $9.4 million in the year ended December 31, 2016. These capital expenditures were funded by cash flows from operations, borrowings under our credit agreement and proceeds from the issuance of common units. We currently expect our expansion capital expenditures for organic growth projects to be approximately $10.0 million to $12.0 million, net of reimbursable expenditures, in 2018. Maintenance capital expenditures totaled $7.9 million, net of reimbursable expenditures of $0.8 million, in the year ended December 31, 2017, compared to $8.7 million in the year ended December 31, 2016. We currently expect maintenance capital expenditures to be approximately $8.0 million to $10 million, net of reimbursable expenditures, in 2018. Our sources of liquidity for these expansion and maintenance capital expenditures in 2018 are expected to be a combination of cash flows from operations and borrowings under our credit agreement.

Our Ability to Grow Depends on Our Ability to Access External Expansion Capital. Our partnership agreement requires that we distribute all of our available cash to our unitholders. Available cash is reduced by cash reserves established by our

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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 agreement. 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 Agreement. On May 11, 2017, we entered into an amended and restated credit agreement which consists of a $450.0 million revolving loan facility.

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.

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 the consent of the new or increasing lenders and an aggregate maximum of $600.0 million for all revolving loan commitments under our credit agreement.

The credit agreement will mature on May 11, 2022, and all amounts outstanding under our credit agreement shall become due and payable on such date. The credit agreement requires mandatory prepayments of amounts outstanding thereunder with the net proceeds from certain asset sales, property or casualty insurance claims and condemnation proceedings, unless we reinvest such proceeds in accordance with the credit agreement, but these mandatory prepayments will not require any reduction of the lenders' commitments under the credit agreement.

Borrowings under our credit agreement bear interest, at our option, at either the reserve-adjusted eurodollar rate (as defined in the credit agreement) plus an applicable margin which ranges from 2.0% to 3.0% or the alternate base rate (the highest of the agent bank's prime rate, the federal funds effective rate plus 0.5%, and the 30-day eurodollar rate plus 1.0%) plus an applicable margin which ranges from 1.0% to 2.0%.

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

The credit agreement includes financial covenants which are tested on a quarterly basis, based on the rolling four-quarter period that ends on the last day of each fiscal quarter.

Prior to the date on which we issue qualified senior notes in an aggregate principal amount (when combined with all other qualified senior notes previously or concurrently issued) that equals or exceeds $200.0 million, the maximum permitted consolidated total leverage ratio is 4.75 to 1.00; provided that the maximum permitted consolidated total leverage ratio will be 5.25 to 1.00 for certain quarters based on the occurrence of a specified acquisition (as defined in the Partnership's credit agreement, but generally being an acquisition for which the aggregate consideration is $15.0 million or more). The acquisition of the nine asphalt terminals from Ergon in 2016 qualified as a specified acquisition.

From and after the date on which we issue qualified senior notes in an aggregate principal amount (when combined with all other qualified senior notes previously or concurrently issued) that equals or exceeds $200.0 million, the maximum permitted consolidated total leverage ratio is 5.00 to 1.00; provided that from and after the fiscal quarter ending immediately preceding the fiscal quarter in which a specified acquisition occurs to and including the last day of the second full fiscal quarter following the fiscal quarter in which such acquisition occurred, the maximum permitted consolidated total leverage ratio is 5.50 to 1.00.

The maximum permitted consolidated senior secured leverage ratio (as defined in the credit agreement, but generally computed as the ratio of consolidated total secured debt to consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges) is 3.50 to 1.00, but this covenant is only tested from and after the date on which we issue qualified senior notes in an aggregate principal amount (when combined with all other qualified senior notes previously or concurrently issued) that equals or exceeds $200.0 million.

The minimum permitted consolidated interest coverage ratio (as defined in the credit agreement, but generally computed as the ratio of consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges to consolidated interest expense) is 2.50 to 1.00.

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In addition, the 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 equity, make distributions to unitholders and make certain other restricted payments;
- make investments;
- modify the terms of certain 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; and
- make certain amendments to our partnership agreement.

At December 31, 2017, our consolidated total leverage ratio was 4.63 to 1.00 and our consolidated interest coverage ratio was 4.76 to 1.00. We were in compliance with all covenants of our credit agreement as of December 31, 2017.

The credit agreement permits us to make quarterly distributions of available cash (as defined in our partnership agreement) to unitholders so long as no default or event of default exists under the credit agreement on a pro forma basis after giving effect to such distribution. We are currently allowed to make distributions to our unitholders in accordance with this covenant; however, we will only make distributions to the extent we have sufficient cash from operations after establishment of cash reserves as determined by the General Partner in accordance with our cash distribution policy, including the establishment of any reserves for the proper conduct of our business.

In addition to other customary events of default, the credit agreement includes an event of default if:

(i) our General Partner ceases to own 100% of our general partner interest or ceases to control us;

(ii) Ergon ceases to own and control 50.0% or more of the membership interests of our General Partner; or

(iii) during any period of 12 consecutive months, a majority of the members of the Board of our General Partner ceases to be composed of individuals:

(A) who were members of the Board on the first day of such period;

(B) whose election or nomination to the Board was approved by individuals referred to in clause (A) above constituting at the time of such election or nomination at least a majority of the Board; or

(C) whose election or nomination to the Board was approved by individuals referred to in clauses (A) and (B) above constituting at the time of such election or nomination at least a majority of the Board,

provided that any changes to the composition of individuals serving as members of the Board approved by Ergon will not cause an event of default.

If an event of default relating to bankruptcy or other insolvency events occurs with respect to our General Partner or us, 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.

Contractual Obligations. A summary of our contractual cash obligations over the next several fiscal years as of December 31, 2017, is as follows:

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Contractual Obligations	Payments Due by Period Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
	(in millions)				
Debt obligations[(1)]	$368.8	$14.0	$28.1	$326.7	$ —
Operating lease obligations	12.9	4.8	5.0	1.8	1.3

(1) Represents required future principal repayments of borrowings of $307.6 million and variable-rate interest payments of $61.2 million. All amounts outstanding under our credit agreement mature in May 2022. For our variable-rate debt, we calculated interest obligations assuming the weighted average interest rate of our variable-rate debt at December 31, 2017, on amounts outstanding through the assumed repayment date.

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 consolidated financial statements in conformity with accounting principles generally accepted in the United States of America. 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 ongoing 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 consolidated 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 operating income in the consolidated statements of operations.

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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.

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. If the fair value of a reporting unit exceeds its carrying amount, goodwill of the reporting unit is not considered to be 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 the Partnership's estimated discounted future net cash flows include existing and estimated future asset utilization, estimated growth rates in future cash flows and estimated terminal values. During the fourth quarter of 2015, our goodwill impairment test indicated that the fair value of the asphalt services and crude oil trucking and producer field services reporting units exceeded their carrying values and no impairments were indicated. In 2016, an impairment was indicated in the crude oil pipeline services reporting unit and an impairment expense of $7.5 million was recorded. In 2017, an impairment was indicated in the crude oil trucking and field services reporting unit and an impairment expense of $0.9 million was recorded.

Recent Accounting Pronouncements

For information regarding recent accounting developments that may affect our future financial statements, see Note 22 to our consolidated financial statements.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

Interest Rate Risk. We are exposed to market risk due to variable interest rates under our credit agreement. As of March 1, 2018, we had $308.6 million outstanding under our credit agreement that was subject to a variable interest rate. Borrowings under our credit agreement bear interest, at our option, at either the reserve adjusted eurodollar rate (as defined in the credit agreement) plus an applicable margin or the alternate base rate (the highest of the agent bank's prime rate, the federal funds effective rate plus 0.5%, and the 30-day eurodollar rate plus 1.0%) plus an applicable margin. Interest rate swap agreements are used to manage a portion of the exposure related to changing interest rates by converting floating-rate debt to fixed-rate debt. In March 2014, we entered into two interest rate swap agreements with an aggregate notional value of $200.0 million. The first agreement became effective June 28, 2014, and matures on June 28, 2018. Under the terms of the first interest rate swap agreement, we pay a fixed rate of 1.45% and receive one-month LIBOR with monthly settlement. The second agreement became effective January 28, 2015, and matures on January 28, 2019. Under the terms of the second interest rate swap agreement, we pay a fixed rate of 1.97% and receive one-month LIBOR with monthly settlement. The fair market value of the interest rate swaps at December 31, 2017, consists of a current asset of $0.1 million and a long-term liability of $0.2 million recorded on the consolidated balance sheets in other current assets and in long-term interest rate swap liabilities, respectively. The interest rate swaps do not receive hedge accounting treatment under ASC 815 - Derivatives and Hedging. Changes in the fair value of the interest rate swaps are recorded in interest expense in the consolidated statements of operations.

During the year ended December 31, 2017, the weighted average interest rate under our credit agreement was 4.43%.

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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, 2017, the terms of our credit agreement, current interest rates and the effect of our interest rate swap agreements, an increase or decrease of 100 basis points in the interest rate would result in increased or decreased annual interest expense of approximately $1.1 million.

Commodity Price Risk. As we do not take ownership of the liquid asphalt or crude oil we terminal or transport for our customers and as we engage in limited commodity marketing, we have limited direct exposure to risks associated with changes in liquid asphalt and crude oil prices. However, the volumes of liquid asphalt and crude oil we gather, transport, market or terminal are indirectly affected by commodity prices because many of our customers have direct commodity price exposure. We do not intend to mitigate this risk to our revenues by hedging this limited commodity price exposure. For additional information regarding the anticipated impact of this risk on our future revenues, see "Item 7-Management's Discussion and Analysis of Financial Condition and Results of Operations-Potential Impact of Crude Oil Market Price Changes and Other Factors on Future Revenues."

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-32 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 Rules 13a-15(e) and 15d-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 were not effective as of December 31, 2017, due to the material weakness in internal control over financial reporting as described below.

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" (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of our annual or unaudited interim financial statements will not be prevented or detected on a timely basis. Management did not maintain effective controls over the presentation of transactions within the consolidated statement of cash flows. Specifically, in connection with the preparation of our financial statements for the year ended December 31, 2017, management identified a material weakness in the operating effectiveness of internal control over financial reporting related to our process for identifying and presenting the non-cash components of an acquisition transaction. This material weakness was identified prior to the issuance of our consolidated financial statements for the year ended December 31, 2017, and resulted in an adjustment to the consolidated financial statements. Additionally, this material weakness could result in misstatements of cash flows that would result in a material misstatement to the annual or interim consolidated financial statements that would not be prevented or detected.

As a result of the material weakness described above, management concluded that our internal control over financial reporting was not effective as of December 31, 2017, based on the criteria established in “Internal Control - Integrated Framework” (2013) issued by the COSO. The effectiveness of our internal control over financial reporting as of December 31, 2017, 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 during the quarter ended December 31, 2017 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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Remediation Activities. To address the material weakness, management will implement a remediation plan which will supplement the existing controls. The remediation plan will include additional training of financial reporting personnel with respect to the preparation of the consolidated statements of cash flows with specific focus on the control that identifies non-cash components of transactions on the statement of cash flows. The material weakness will be fully remediated when, in the opinion of management, the control processes have been operating for a sufficient period of time to provide reasonable assurance as to their effectiveness. The remediation and ultimate resolution of the material weakness will be reviewed with the Audit Committee of the Board.

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 operations. 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. Borrowings under our existing credit facility are nonrecourse to our General Partner.

Directors and Executive Officers

The Board currently consists of W. R. “Lee” Adams (affiliated with Ergon), Edward D. Brooks (affiliated with Ergon), Jimmy A. Langdon (affiliated with Ergon), Robert H. Lampton (affiliated with Ergon), William W. Lampton (affiliated with Ergon), 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.

The following table shows information regarding the current directors and executive officers of our General Partner as of March 1, 2018.

Name	Age	Position with Blueknight Energy Partners G.P., L.L.C.
Mark A. Hurley	59	Chief Executive Officer
Alex G. Stallings	50	Chief Financial Officer and Secretary
Joel W. Kanvik	48	Chief Legal Officer and General Counsel
James R. Griffin	40	Chief Accounting Officer
Jeffery A. Speer	51	Chief Operating Officer
Brian L. Melton	48	Chief Commercial Officer
Duke R. Ligon	76	Director, Chairman of the Board and Audit Committee
Steven M. Bradshaw	69	Director, Chairman of the Conflicts Committee
John A. Shapiro	66	Director, Chairman of the Compensation Committee
W.R. “Lee” Adams	49	Director
Edward D. Brooks	35	Director
Jimmy A. Langdon	53	Director
Robert H. Lampton	57	Director
William W. Lampton	62	Director

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. Robert H. Lampton and William W. Lampton are brothers. There are no other family relationships between officers and directors.

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 was also previously an audit manager for the public accounting firm of Coopers & Lybrand, working in its Tulsa, Oklahoma office. Mr. Stallings received his Bachelor of Business Administration in accounting from Baylor University and is a certified public accountant in the state of Oklahoma.

Joel W. Kanvik has served as General Counsel and Chief Legal Officer of our General Partner since November 2016. Mr. Kanvik previously served as the Director of U.S. Law and Assistant Secretary for Enbridge Energy Company, Inc., which he joined in January 2001. He provided legal and business counsel to a family of corporations/limited partnerships, including the development and execution for large-scale construction/acquisition projects, mergers and acquisitions, contracts and licenses, intellectual property, litigation management and corporate governance. Mr. Kanvik received his Bachelor of Arts in political science from Northwestern University and his Juris Doctor from the University of Wisconsin.

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. Mr. Griffin previously served as an audit manager for the public accounting firm of PricewaterhouseCoopers LLP. Mr. Griffin received his Bachelor of Science in business administration from Oklahoma State University and is a certified public accountant in the state of Oklahoma.

Jeffery A. Speer has served as Chief Operating Officer of our General Partner since July 2013. Mr. Speer served as Senior Vice President-Operations of our General Partner from February 2010 to July 2013. Previously, Mr. Speer served as the Vice President of Operations of our asphalt and emulsion subsidiary since June 2009. Prior to joining our team, Mr. Speer served as Vice President of Operations for Koch Industries, Inc. and had operational responsibility for Koch's crude oil, pipeline and trucking divisions in Oklahoma, Texas and Canada, as well as Koch's agricultural and asphalt businesses. Mr. Speer has more than 27 years of experience in the energy industry and received his Bachelor of Science in mechanical engineering from Kansas State University.

Brian L. Melton has served as Chief Commercial Officer since January 2017 and previously as Vice President Pipeline Marketing and Business Development of our General Partner since December 2013. Previously, he served as Vice President of Business Development/Corporate Strategy for Crestwood Equity Partners, L.P., Crestwood Midstream Energy Partners, L.P. and Inergy, L.P. from September 2008 until December 2013. Prior to joining Inergy in 2008, he was a director in the Energy Corporate Investment Banking groups of A.G. Edwards/Wachovia Securities. He has served on the board of directors of Abraxas Petroleum Corporation since October of 2009. Mr. Melton received his Bachelor of Science in management and his Master of Business Administration in finance from Arkansas State University.

Duke R. Ligon has served as a director of our General Partner since October 2008. He is an attorney and the current owner and manager of Mekusukey Oil Company, LLC. He served as Senior Vice President and General Counsel of Devon Energy Corporation from January 1997 until he retired in February 2007. From February 2007 to February 2010, Mr. Ligon served in the capacity of Strategic Advisor to Love's Travel Stops & Country Stores, Inc., based in Oklahoma City, Oklahoma, and 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 Heritage Trust Company, Security State

Bank (in which he has a 14% beneficial ownership), Cavaloz Holdings, Inc. and Pardus Oil and Gas. He was formerly on the board of directors of PostRock Energy Corporation, System One, Orion California LP, Emerald Oil, Inc., SteelPath MLP, TransMontaigne Partners L.P., Pre-Paid Legal Services, Inc., Panhandle Oil and Gas Inc.,Vantage Drilling Company and TEPPCO Partners, L.P. Mr. Ligon received his undergraduate degree in chemistry from Westminster College and his 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 35 years of experience in the global logistics and transportation industry and currently serves as the Managing Director at Global Logistics Solutions. 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 international oil and gas industry. Previously, he served as Executive Vice President of Skaugen PetroTrans, Inc. from 2001 to 2003. He also served for 16 years in various operating and marketing capacities at Kirby Corporation, including as President-Refined Products Division from 1992 to 1996. Mr. Bradshaw also served as an officer in the United States Navy. He received his Master of Business Administration from Harvard University and a bachelor's degree in mathematics from the University of Missouri. 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 Citymeals-on-Wheels and serves as a senior advisor to Mountain Capital Partners, a Houston-based private equity firm focused on upstream E&P investments. Mr. Shapiro has served on the board of directors of Blue Wolf Mongolia Holdings. He received his Master of Business Administration from Harvard University and his bachelor's degree in economics from Princeton University. Mr. Shapiro was selected to serve as a director on the Board due to his financial expertise and extensive industry experience developed through his work at Morgan Stanley & Co., and by serving as a director of other energy companies.

W.R. "Lee" Adams has served as a director of our General Partner since February 2018. Mr. Adams joined Ergon, Inc. as the Vice President of Internal Audit in 2011 and continues to serve in that position. He also serves as Chairman of Ergon's Senior Management Team. He is a certified public accountant in the state of Mississippi and previously worked at Arthur Anderson and Haddox Reid Burkes & Calhoun, PLLC, where he specialized in assurance and advisory services in the areas of oil and gas, manufacturing, investments and employee benefit plans. Mr. Adams received his Bachelor of Accountancy from Mississippi State University, and also holds the designations of Chartered Global Management Accountant, Certified Fraud Examiner and Certified Internal Auditor. Mr. Adams currently serves as a member of the advisory council for Mississippi State's Adkerson School of Accountancy and is the Chairman of the Board of Hartfield Academy. He has previously served as Chairman/President of the Petroleum Accounting Society of Mississippi and of the Mississippi Society of Certified Public Accountants, a 2,600-member trade association for CPAs practicing in the state of Mississippi. Mr. Adams was selected to serve as a director on the Board due to his affiliation with Ergon and his financial and business expertise.

Edward D. Brooks has served as a director of our General Partner since October 2016. Mr. Brooks has been the Vice President of Business Development for Ergon Asphalt & Emulsions, Inc. since 2013. Mr. Brooks joined Ergon in 2007 to serve as the Manager of Business Development. Prior to joining Ergon, Mr. Brooks worked with Haddox Reid Burkes & Calhoun, PLLC as a manager in the assurance services division. Mr. Brooks received his Bachelor of Science in Business Administration in accounting and his Master of Business Administration from Mississippi College and is a certified public accountant in the state of Mississippi. He also holds a Chartered Global Management Accountant designation. Mr. Brooks was selected to serve as a director on the Board due to his affiliation with Ergon and his financial and business expertise.

Jimmy A. Langdon has served as a director of our General Partner since October 2016. Mr. Langdon currently holds the following positions: Executive Vice President and Chief Operating Officer for Ergon; Sr. Vice President for ISO Panels, Inc.; Sr. Vice President for Ergon Teminalling, Inc.; Sr. Vice President for Ergon Baton Rouge, Inc.; Sr. Vice President for Ergon Knoxville, Inc.; Sr. Vice President for Ergon St. James, Inc.; Sr. Vice President for Ergon Texas Pipeline, Inc.; and Sr. Vice President for Ergon-Ironton, LLC. He also serves on the Ergon Operating Committee as the chairman and Ergon's Executive Committee as a member. Mr. Langdon began his full-time professional career with Tenneco working as an associate engineer with their Tennessee Gas Pipeline group based in Houston, Texas. He joined Ergon Refining, Inc. in 1989 as a maintenance engineer in Vicksburg, Mississippi and held various other positions through 1997. In 1997, he assisted Ergon with the formation of Ergon-West Virginia, Inc. in Newell, West Virginia and held the position of Maintenance/Engineering Manager until 2000. In 2000, Mr. Langdon joined the Ergon corporate office group and assisted the Real Estate segment of the company for the next two years in the development business. Over the next 14 years, he held various positions within Ergon including Vice President-Corporate Engineering and Vice President-Corporate Maintenance, as well as Sr. Vice President for Ergon Asphalt & Emulsions, Inc. Mr. Langdon received his degree in civil engineering from Mississippi State University. Mr. Langdon was selected to serve as a director on the Board due to his affiliation with Ergon and his financial and business expertise.

Robert H. Lampton has served as a director of our General Partner since October 2016. Mr. Lampton has been with Ergon since 1983, and currently serves as President of the Supply and Distribution Division, President of Ergon Terminalling, Inc. and President of Ergon Trucking, Inc. Mr. Lampton is also President of Ergon Marine and Industrial Supply and of Ergon Real Estate. He serves on Ergon’s Executive Committee and is a member of their board of directors. He was a board member for Mississippi Valley Title Company from 2005 to 2015. Mr. Lampton received his degree in business administration with a

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minor in business psychology from The University of Mississippi. Mr. Lampton was selected to serve as a director on the Board due to his affiliation with Ergon and his financial and business expertise.

William W. Lampton has served as a director of our General Partner since October 2016. Mr. Lampton has been with Ergon since 1979, and currently is a member of Ergon's board of directors. He previously served as President of Ergon's Asphalt Groups and as Chairman of the board of directors of Ergon Asphalt & Emulsions, Inc. Mr. Lampton currently is a board member of Mississippi Economic Council, Boy Scouts of America, Andrew Jackson Council, Greater Jackson Chamber Partnership (of which he is a past chairman), and Mississippi Baptist Health Foundation. He sits on the Dean's Advisory Council of Mississippi State University's Bagley College of Engineering, and served as co-chair of the Mississippi Works initiative under Governor Phil Bryant. Mr. Lampton was selected to serve as a director on the Board due to his affiliation with Ergon and his financial and business expertise.

Independence of Directors

Our General Partner currently has eight 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 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 the Board, 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 the Board.

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 6060 American Plaza, Suite 600, Tulsa, Oklahoma 74135. 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.

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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 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 incorporates guidelines designed to deter wrongdoing and to promote honest and ethical conduct and compliance with applicable laws and regulations. It also incorporates 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 - Code of Business Conduct and Ethics" 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 6060 American Plaza, Suite 600, Tulsa, Oklahoma 74135. 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 all directors, officers, beneficial owners of more than 10% of any class of our securities or any other person subject to Section 16 of the Exchange Act complied with the Section 16(a) filing requirements of them during the year ended December 31, 2017, except for one Form 4 filed late on behalf of one of our directors in February 2018 with respect to one transaction.

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 2017, each person who served as the Principal Financial Officer ("PFO") during 2017 and the three most highly compensated executive officers other

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than the PEO and PFO serving at December 31, 2017, 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, 2017, are referred to as the Named Executive Officers ("NEOs"). The NEOs during 2017 were:

- Mark A. Hurley, Chief Executive Officer;
- Alex G. Stallings, Chief Financial Officer and Secretary;
- Jeffery A. Speer, Chief Operating Officer;
- Brian L. Melton, Chief Commercial Officer; and
- Joel W. Kanvik, Chief Legal Officer and General Counsel.

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. The compensation for the NEOs for services rendered to us is determined by the compensation committee of our General Partner.

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. Once every two to three years, our compensation committee examines the compensation practices of certain of our peer companies which, as of our most recent examination in March 2017, includes Sprague Resources, LP; CrossAmerica Partners, LP; Martin Midstream Partners, L.P.; Southcross Energy Partners, L.P.; JP Energy Partners, LP; Summit Midstream Partners, LP; American Midstream Partners, LP; CONE Midstream Partners, LP; Transmontaigne Partners, L.P.; PBF Logistics, LP; World Point Terminals, LP; Noble Midstream Partners, LP; Arc Logistics Partners, LP; USD Partners, LP and PennTex Midstream Partners, LP. 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 March 2017, the compensation committee of the Board engaged Aon Hewitt ("Aon") as its independent compensation consultant to provide the compensation committee with comparable market-based compensation data applicable to the NEOs of our General Partner. In its consultation role, Aon was tasked with conducting an assessment of our peer group and benchmarking the compensation of our NEOs against our peer group.

The objective of the analysis was to review and ensure the market competitiveness of our NEOs' compensation. The scope of Aon's review included the market competitiveness of the following compensation elements:

- base salary;
- target annual incentive opportunity (annual incentive paid for achieving target performance levels);
- target total annual compensation (base salary + target annual incentive);
- long-term incentive ("LTI") awards; and
- target total direct compensation (base salary + target annual incentive + LTI awards).

Market data presented by Aon represented the compensation paid to a "typical" employee in a particular position and was considered as one data point when making compensation determinations. Individual performance, longevity and internal equity were also factors in determining individual pay levels. The compensation committee expects to continue to utilize the compensation survey data when making decisions to change any individual NEO's compensation, or when making changes or additions to any compensation program or methodologies. Aon's work for the compensation committee did not raise any conflicts of interest in 2017.

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 NEOs in 2017 were as follows:

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

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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 NEOs. 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. Our General Partner's compensation committee establishes base salaries for the NEOs and reviews these annually considering various factors, including the amounts it considers 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.

In March 2017, our General Partner's compensation committee increased the base salaries of Messrs. Hurley, Stallings, Speer, Melton and Kanvik to $450,000, $326,000, $268,000, $244,000 and $260,000, respectively. These base salary increases reflected the scope of each executive's responsibilities and the compensation committee's consideration of competitive market compensation paid by similar companies for comparable positions.

Discretionary Bonus Awards. Our General Partner's compensation committee may also award discretionary bonus awards to the NEOs. Our General Partner grants discretionary bonus awards to encourage and reward achievement of financial and operational goals and individual performance objectives.

During March 2018, the compensation committee awarded discretionary bonuses of $400,000, $160,000, $187,000, $110,000 and $141,000 to each of Messrs. Hurley, Stallings, Speer, Melton and Kanvik, respectively, relating to our results of operations in 2017. Please see "-2017 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 NEOs is 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."

During March 2017, the compensation committee made awards of 21,800, 22,504, 15,471 and 12,658 phantom units to Messrs. Stallings, Speer, Melton and Kanvik, respectively, relating to our results of operations in 2016. The awards vest on January 1, 2020. 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.

During March 2018, the compensation committee made awards of 61,448, 27,447, 29,700, 19,663 and 20,278 phantom units to Messrs. Hurley, Stallings, Speer, Melton and Kanvik, respectively, relating to our results of operations in 2017. For all but Mr. Hurley, the awards vest on January 1, 2021. Mr. Hurley's phantom units will vest on January 1, 2019. 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 "-2017 Incentive Compensation" for a discussion of these awards.

Other Benefits. The employment agreements entered into by Messrs. Hurley and Stallings 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 2017, our General Partner, in addition to the Long-Term Incentive Plan described above, maintained an employee health insurance plan and an Exec-U-Care plan under which our officers (including all NEOs) were reimbursed for certain co-pays and deductibles for medical expenses. In addition, the employment agreements provide that each NEO is entitled to reimbursement for out-of-pocket expenses incurred while performing his duties under the employment agreement. Furthermore, we currently provide auto allowances to our NEOs.

2017 Incentive Compensation. For 2017, the Board approved a cash bonus plan whereby 90% of an aggregate bonus pool for all employees, including the NEOs, was to be funded as follows:

- 75% of this portion of the bonus pool was to be funded based on the achievement of approximately $54.6 million in cash flow generated prior to distributions, incentive compensation and reserves established by our General Partner.

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- An additional 15% of this portion of the bonus pool was to be funded based on the achievement of partnership-wide goals (with a range of 0% to 15% being contributed based on this performance metric).
- An additional 10% of this portion of the bonus pool was to be funded based on the achievement of environmental, health and safety targets (with a range of 0% to 20% being contributed based on this performance metric).

An additional 10% of the bonus pool was to be funded based on the achievement of our growth goals (with a range of 0% to 20% being contributed based on this performance metric).

Individual awards (which, as in prior years, were expected to be paid in a combination of cash bonuses and equity compensation) were to be determined by the compensation committee at 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. In 2017, actual cash flow generated prior to distributions, incentive compensation and reserves established by our General Partner was $52.6 million, resulting in 65% of the bonus pool being contributed based on this metric. In addition, partnership-wide goals were achieved resulting in 15% of the bonus pool being contributed, 9% of the bonus pool was contributed based on the partial achievement of environmental, health and safety targets and company growth goals were partially met resulting in 7% of the bonus pool being contributed.

In March 2018, our General Partner’s chief executive officer recommended cash bonus and Long-Term Incentive Plan awards for the remaining NEOs. After a thorough discussion, the compensation committee approved the following for each of our NEOs (other than Mr. Hurley):

(i) a discretionary bonus award relating to our results of operations in 2017 as follows: $160,000, $187,000, $110,000 and $141,000 for Messrs. Stallings, Speer, Melton and Kanvik, respectively; and
(ii) awards of phantom units relating to our results of operations for 2017 as follows: 27,447 units, 29,700 units, 19,663 units and 20,278 units to Messrs. Stallings, Speer, Melton and Kanvik, respectively.

On March 5, 2018 the compensation committee made these discretionary bonus awards and phantom unit grants in accordance with such recommendations and also awarded Mr. Hurley a discretionary bonus award of $400,000 relating to our results of operations in 2017. The discretionary bonus awards were paid in March 2018. The compensation committee considered the achievement of performance metrics outlined in the prior paragraph as well as the performance of the individual NEO in determining to make such awards.

Role of Executive Officers in Executive Compensation. Our General Partner’s compensation committee determines the compensation of the NEOs. 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 NEOs relating to our results of operations in 2017. However, Mr. Hurley does not make any recommendations regarding his personal compensation. In addition, the employment agreement entered into by Mr. Stallings was 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 NEOs except Messrs. Speer, Melton and Kanvik has entered into an employment agreement with our General Partner or one of its subsidiaries.

Employment Agreement of Mr. Hurley. Mr. Hurley’s employment agreement had an initial term of five years that now automatically renews for subsequent one-year periods unless either party gives 90 days advance notice of termination. Pursuant to Mr. Hurley’s employment agreement, Mr. Hurley was paid an initial annual base salary of $425,000. Our General Partner’s compensation committee has increased the base salary of Mr. Hurley to $450,000 since the initial employment agreement. Mr. Hurley also received 500,000 non-participating phantom units in September 2012 under the General Partner’s Long-Term Incentive Plan, which vested ratably over five years pursuant to the Phantom Unit

Agreement he entered into with the General Partner. The units were fully vested as of December 31, 2017. 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 his employment agreement and has agreed to a one-year post-termination non-solicitation covenant.

Except in the event of termination for Cause as defined therein, termination by Mr. Hurley other than for Good Reason as defined therein, 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 12 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 18 months following termination. Based upon Mr. Hurley’s current base salary, the maximum amount of the lump sum severance payment would be approximately $0.5 million, in addition to continued participation in the General Partner’s welfare benefit programs and the amounts of earned but unpaid base salary and benefits under any incentive plans.

The 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.” Pursuant to the employment agreement, if, within 18 months after a Change of Control (as defined therein) occurs, Mr. Hurley is terminated by our General Partner without Cause (as defined therein) or Mr. Hurley terminates the agreement for Good Reason (as defined therein), he will be entitled to payment of any unpaid base salary and vested benefits under any incentive plans, a lump sum payment equal to 12 months of base salary and Mr. Hurley’s most recent annual bonus 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. Based upon Mr. Hurley’s current base salary and most recent annual bonus, the maximum amount of the lump sum severance payment would be approximately $0.9 million, in addition to continued participation in the General Partner’s welfare benefit programs and the amounts of earned but unpaid base salary and benefits under any incentive plans.

Employment Agreement of Mr. Stallings. The employment agreement entered into by Mr. Stallings had an initial term of two years that automatically renews for subsequent one-year periods unless either party gives 90 days advance notice of termination. This employment agreement provides for Mr. Stallings’ annual base salary as described above. In addition, Mr. Stallings is eligible for discretionary bonus awards and long-term incentives which may be made from time to time at the sole discretion of the Board. The employment agreement also provides that Mr. Stallings is 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 is entitled to reimbursement for certain out-of-pocket expenses.

Pursuant to the employment agreement, Mr. Stallings has agreed not to disclose any confidential information obtained by him while employed under the agreement. In addition, the 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 Mr. Stallings, our General Partner may be required to pay certain amounts upon a Change of Control (as defined therein) of us or our General Partner or upon the termination of Mr. Stallings in certain circumstances. Except in the event of termination for Cause (as defined therein), termination by Mr. Stallings other than for Good Reason (as defined therein) or termination after the expiration of the term of the employment agreement, the employment agreement provides for payment of any unpaid base salary and vested benefits under any incentive plans, a lump sum payment equal to 12 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.

The employment agreement also provides that if, within one year after a Change of Control (as defined therein) occurs, Mr. Stallings is terminated by our General Partner without Cause (as defined therein) or Mr. Stallings terminates the agreement for Good Reason (as defined therein), 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. Based upon Mr. Stallings’ current base salary, the maximum amount of the lump sum severance payment would be approximately $0.7 million, in addition to continued participation in the General Partner’s welfare benefit programs and the amounts of earned but unpaid base salary and benefits under any incentive plans.

Potential Payments Upon Change of Control.

As described above, the employment agreements with Messrs. Hurley and Stallings contain provisions that could result in the payment of amounts described above to such individuals upon a qualifying termination or Change of Control (as defined in such employment agreements).

Had Messrs. Hurley or Stallings been terminated under the scenarios listed below on December 31, 2017, they would have received the following amounts and benefits:

Name	Benefit Type	Termination without Cause or Resignation for Good Reason		Termination without Cause or Resignation for Good Reason in Connection with A Change in Control	
Mark A. Hurley	Lump Sum Severance	$ 925,000	(1)	$ 925,000	(1)
	Benefits Continuation	$ —	(2)	$ —	(2)
Alex G. Stallings	Lump Sum Severance	$ 326,000		$ 652,000	
	Benefits Continuation	$ 34,000		$ 34,000	

(1) As described above, on October 5, 2016, Ergon purchased 100% of the outstanding voting stock of Blueknight GP Holding, L.L.C. from Charlesbank Capital Partner, LLC and Vitol Holding B.V., triggering a Change of Control under the employment agreements. Mr. Hurley was still within his 18-month protection period following such Change in Control and, thus, would have been entitled to enhanced severance benefits upon any termination of his employment without Cause or for Good Reason on December 31, 2017.

(2) Mr. Hurley did not participate in our General Partner's group health plans as of December 31, 2017, and thus would not have received any continued benefits under such plans had he experienced a qualifying termination of employment on such date.

Long-Term Incentive Plan. General. Our General Partner has adopted the Long-Term Incentive Plan ("LTIP") for employees, consultants and directors of our General Partner and its affiliates who perform services for us. The summary of the LTIP contained herein does not purport to be complete and is qualified in its entirety by reference to the LTIP. The LTIP provides for the grant of unit awards, restricted units, phantom units, unit options, unit appreciation rights and distribution equivalent rights. Effective April 29, 2014, the Partnership's unitholders voted to approve an amendment to the LTIP, which increased the number of common units reserved for issuance thereunder by 1,500,000 common units, from 2,600,000 common units to 4,100,000 common units, subject to adjustment for certain events. 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 LTIP is administered by the compensation committee of the Board. The LTIP has been designed to furnish additional compensation to employees, consultants and directors and to align their economic interests with those of other common unitholders.

Unit Awards. The compensation committee may grant unit awards to eligible individuals under the LTIP. 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, at 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 LTIP to eligible individuals containing such terms, consistent with the LTIP, as the compensation committee may determine, including the period over which restricted units and phantom units granted will vest. The compensation committee may, at its discretion, base vesting on the grantee's completion of a period of service or upon the achievement of specified performance goals or other criteria.

Distributions made by us with respect to awards of restricted units may, at the compensation committee's discretion, be subject to the same vesting requirements as the restricted units. The compensation committee, at 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 LTIP 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 LTIP 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 LTIP; 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.

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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.

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 LTIP. The Board, at its discretion, may terminate the LTIP at any time with respect to the units for which a grant has not theretofore been made. The LTIP 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 LTIP. The Board will also have the right to alter or amend the LTIP 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.

Unit Purchase Plan. On June 23, 2014, the Partnership's unitholders approved the Blueknight Energy Partners, L.P. Employee Unit Purchase Plan (the "Unit Purchase Plan"). The Unit Purchase Plan provides employees of the General Partner and its affiliates who perform services for the Partnership the opportunity to acquire or increase their ownership of common units. Eligible employees who enroll in the Unit Purchase Plan may elect to have a designated whole percentage (ranging from 1% to 15%) of their eligible compensation for each pay period withheld for the purchase of common units. A maximum of 1,000,000 common units may be delivered under the Unit Purchase Plan, subject to adjustment for a recapitalization, split, reorganization or similar event pursuant to the terms of the Unit Purchase Plan. The purpose of the Unit Purchase Plan is to promote our interests by providing employees of the General Partner and its affiliates a cost-effective program to enable them to acquire or increase their ownership of common units and to provide a means whereby such individuals may develop a sense of proprietorship and personal involvement in our development and financial success, and to encourage them to devote their best efforts to our business, thereby advancing our interests. As of December 31, 2017, 154,961 common units have been delivered under the Unit Purchase Plan.

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Summary Compensation Table

The following table summarizes the compensation of our NEOs for the years ended 2017, 2016 and 2015. Mr. Kanvik was not an NEO in 2016 or 2015.

Name and Position	Year	Salary ($)	Bonus ($)(1)	Stock Awards ($)(2)	Option Awards ($)	Non-Equity Incentive Compensation ($)	All Other Compensation ($)(3)	Total ($)
Mark A. Hurley Chief Executive Officer	2017	448,750	400,000	—	—	—	42,991	891,741
	2016	445,000	475,000	—	—	—	43,075	963,075
	2015	442,500	450,000	—	—	—	43,929	936,429
Alex G. Stallings Chief Financial Officer and Secretary	2017	324,450	160,000	155,870	—	—	76,541	716,861
	2016	319,800	165,000	142,528	—	—	71,237	698,565
	2015	317,850	145,000	120,187	—	—	63,228	646,265
Jeffery A. Speer Chief Operating Officer	2017	258,333	187,000	160,904	—	—	73,424	679,661
	2016	237,000	160,000	175,784	—	—	65,310	638,094
	2015	226,105	135,000	106,951	—	—	59,535	527,591
Brian L. Melton Chief Commercial Officer	2017	242,250	110,000	110,611	—	—	60,578	523,439
	2016	237,000	155,000	104,520	—	—	57,005	553,525
	2015	235,250	155,000	101,858	—	—	45,154	537,262
Joel W. Kanvik Chief Legal Officer	2017	260,000	256,000	90,505	—	—	29,401	635,906

(1) In connection with his appointment as Chief Commercial Officer, Mr. Melton received a signing bonus, of which $45,000 was paid in both 2015 and 2016. In connection with his appointment as Chief Legal Officer, Mr. Kanvik received a signing and relocation bonus, of which $115,000 was paid in 2017.

(2) Dollar amounts represent the grant date fair value of awards granted in each year with respect to phantom unit grants under the LTIP. See Note 14 to our consolidated financial statements for assumptions used in calculating these amounts.

(3) We provide distribution equivalent rights (“DERs”) under the LTIP, auto allowances, reimbursement of certain deductibles and co-pays for medical expenses and discretionary matching and profit sharing contributions to our 401(k) plan to our NEOs. In 2017, payments of $35,820, $39,178, $27,072 and $5,506 related to the DERs were made to Messrs. Stallings, Speer, Melton and Kanvik, respectively. In 2017, auto allowances of $10,800 were paid each to Messrs. Hurley, Stallings, Speer, Melton and Kanvik. In 2017, matching and profit sharing contributions to our 401(k) plan of $26,910, $26,910, $22,204, $19,348 and $10,578 were made for Messrs. Hurley, Stallings, Speer, Melton and Kanvik, respectively.

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.

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Grants of Plan-Based Awards for Fiscal Year 2017

The following tables provide information concerning each grant of an award made to a NEO during 2017, including, but not limited to, awards made under our General Partner's LTIP.

		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 ($/Sh)	Grant Date Fair Value of Unit and Option Awards ($)
Alex G. Stallings	March 9, 2017	—	—	—	—	—	—	21,800	—	—	155,870
Jeffrey A. Speer	March 9, 2017	—	—	—	—	—	—	22,504	—	—	160,904
Brian L. Melton	March 9, 2017	—	—	—	—	—	—	15,471	—	—	110,611
Joel W. Kanvik	March 9, 2017	—	—	—	—	—	—	12,658	—	—	90,505

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(1) This amount represents grants of phantom units under our General Partner's LTIP. See Note 14 to our consolidated financial statements.
(2) No awards were granted to Mr. Hurley in 2017.

Outstanding Equity Awards at Fiscal Year-End 2017

The following tables provide information concerning all outstanding equity awards made to a NEO as of December 31, 2017, including, but not limited to, awards made under our General Partner's LTIP.

	Option Awards					Stock Awards			
Name	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	Equity Incentive Plan Awards: Market or Payout Value of Unearned Units or Other Rights

						Vested (#)		That Have Not Vested ($)[1][5]
	——	—	—	—	—	21,800	[2]	111,180
Alex G. Stallings	——	—	—	—	—	29,880	[3]	152,388
	——	—	—	—	—	15,528	[4]	79,193
	——	—	—	—	—	22,504	[2]	114,770
Jeffery A. Speer	——	—	—	—	—	26,892	[3]	137,149
	——	—	—	—	—	13,818	[4]	70,472
	——	—	—	—	—	15,471	[2]	78,902
Brian L. Melton	——	—	—	—	—	21,912	[3]	111,751
	——	—	—	—	—	13,160	[4]	67,116
Joel W. Kanvik	——	—	—	—	—	12,658	[2]	64,556

(1) Market value of awards is calculated as the product of the closing market price of $5.10 of the Partnership's common units at December 29, 2017, and the number of phantom units outstanding at December 31, 2017.

(2) Represents phantom units granted in 2017 under our General Partner's LTIP. These phantom units will vest on January 1, 2020. All of the distribution equivalent rights associated with these phantom units are currently payable.

(3) Represents phantom units granted in 2016 under our General Partner's LTIP. These phantom units will vest on January 1, 2019. All of the distribution equivalent rights associated with these phantom units are currently payable.

(4) Represents phantom units granted in 2015 under our General Partner's LTIP. These phantom units vested on January 1, 2018. All of the distribution equivalent rights associated with these phantom units are currently payable.

(5) Mr. Hurley held no equity awards as of December 31, 2017.

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Option Exercises and Stock Vested for Fiscal Year 2017

The following table provides information regarding each vesting during 2017 of phantom units held by our NEOs. Our NEOs have not been granted stock option awards.

Name	Stock Awards[1] Number of Shares Acquired on Vesting (#)	Value Realized on Vesting ($)	
Mark A. Hurley	100,000	575,000	(2)
Alex G. Stallings	17,089	120,477	(3)
Jeffrey A. Speer	16,538	116,593	(3)
Brian L. Melton	12,679	89,387	(3)

(1) No awards vested in 2017 for Mr. Kanvik.

(2) This value is based on the average of the high and low trading prices of our common unit on September 21, 2017, the date of issuance of such common units.

(3) This value is based on the average of the high and low trading prices of our common units on January 17, 2017, the date of issuance of such common units.

Director Compensation for Fiscal Year 2017

Name	Fees Earned or Paid in Cash ($)	Stock Awards[3] ($)	Option Awards ($)	Non-Equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($)	Total ($)
Duke R. Ligon	131,117	55,000	—	—	—	—	186,117
Steven M. Bradshaw	131,117	45,000	—	—	—	—	176,117
John A. Shapiro	131,117	45,000	—	—	—	—	176,117
Donald M. Brooks[1][2]	—	—	—	—	—	—	—
Edward D. Brooks[1]	—	—	—	—	—	—	—
Jimmy A. Langdon[1]	—	—	—	—	—	—	—
Robert H. Lampton[1]	—	—	—	—	—	—	—
William W. Lampton[1]	—	—	—	—	—	—	—

(1) Affiliated with Ergon.

(2) Mr. Brooks resigned from the Board in February 2018.

(3) These amounts represent the grant date fair value of restricted and unrestricted units awarded under the LTIP. The grant date fair value of these awards is computed in accordance with ASC 718 - Compensation—Stock Compensation. See Note 14 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 and committees thereof. Such directors receive the following:

(i) $75,000 per year as an annual retainer fee paid in cash;
(ii) $5,000 per year for each Board committee on which such director serves (except that the chairperson of each committee will receive $10,000 per year for serving as chairperson of such committee), payable in unrestricted common units;
(iii) $10,000 per year if Chairman of the Board, payable in unrestricted common units;
(iv) $2,000 per diem for each Board or committee meeting attended;
(v) 5,000 restricted units upon becoming a director, vesting in one-third increments over a three-year period;
(vi) $25,000 of restricted units based on the grant date fair value 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.

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In addition, each director is fully indemnified by us for actions associated with being a director to the fullest extent permitted under Delaware law.

Pay Ratio Disclosure

We believe our executive compensation program must be consistent and internally equitable to motivate our employees to perform in ways that enhance shareholder value. We are committed to internal pay equity, and the compensation committee monitors the relationship between the pay of our executive officers and the pay of our non-executive employees. The compensation committee reviewed a comparison of our Chief Executive Officer's ("CEO") annual total compensation during fiscal year 2017 to that of our median compensated employee for the same period. For purposes of identifying our median compensated employee we calculated the total of the following amounts based on our payroll records:

- salary received;
- annual bonus;
- auto allowance;
- company-paid group term life insurance;
- fair market value of vesting stock units; and
- company-paid Unit Purchase Plan discount.

We identified all active employees as of December 31, 2017. We then determined our median compensated employee by calculating the sum of the amounts described above for each of our employees, which we annualized for any employee who did not work for the entire year. We ranked the employees from highest to lowest and selected the median employee from this listing. We then calculated the annual total compensation of the median compensated employee and the CEO in accordance with SEC requirements.

Based on our calculation as described above, the 2017 annual total compensation of our CEO was $891,741, the 2017 annual total compensation of our median compensated employee was $70,584 and the ratio of these amounts was 12.6:1. This pay ratio is a reasonable estimate calculated in a manner consistent with SEC rules based on our payroll and employment records and the methodology described above.

Compensation Committee Interlocks and Insider Participation

During the year ended December 31, 2017, 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 or had any relationship requiring disclosure under Item 404 of Regulation S-K.

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 as 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 1, 2018 held by:

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- each person or group of persons who beneficially own 5% or more of the then outstanding common units or Preferred Units;
- all of the directors of our General Partner;
- each NEO of our General Partner; and
- all current directors and NEOs 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 40,310,272 common units and 35,125,202 Preferred Units outstanding as of March 1, 2018.

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
Ergon Asphalt & Emulsions, Inc.[(2)]	2,745,837	6.8%	18,312,968	52.1%	27.9%
Mark A. Hurley[(5)]	362,999	*	—	—	*
Alex G. Stallings[(3)(5)]	97,834	*	20,000	*	*
Jeffery A. Speer[(5)]	52,031	*	—	—	*
Joel W. Kanvik	3,982	*	—	—	*
Brian L. Melton[(5)]	22,371	*	400	*	*
Duke R. Ligon[(4)]	58,101	*	—	—	*
Steven M. Bradshaw[(4)]	39,356	*	—	—	*
John A. Shapiro[(4)]	37,766	*	—	—	*
W.R. “Lee” Adams[(2)(6)]	50,000	*	—	—	*
Edward D. Brooks[(2)(6)]	—	—	—	—	—
Jimmy A. Langdon[(2)(6)]	—	—	—	—	—
Robert H. Lampton[(2)(6)]	150,000	*	—	—	*
William W. Lampton[(2)(6)]	103,350	*	—	—	*
Blueknight Energy Holding, Inc.[(7)]	—	—	2,488,789	7.1%	3.3%
CB-Blueknight, LLC[(8)]	—	—	2,488,789	7.1%	3.3%
MSD Capital, L.P.[(9)]	240,000	*	1,907,711	5.4%	2.8%
Swank Capital, L.L.C.[(10)]	4,430,929	11.0%	2,269,729	6.5%	8.9%
Neuberger Berman Group LLC[(11)]	6,175,108	15.3%	—	—	8.2%
DG Capital Management, Inc.[(12)]	3,175,947	7.9%	—	—	4.2%
Clearbridge Investments, LLC[(13)]	3,278,894	8.1%	—	—	4.3%
Oppenheimer Funds, Inc.[(14)]	2,825,482	7.0%	—	—	3.7%
All current executive officers and directors as a group (14 persons)	1,037,212	2.6%	20,400	*	1.4%

*Less than 1%.

(1) Unless otherwise indicated, the address for all beneficial owners in this table is 6060 American Plaza, Suite 600, Tulsa, Oklahoma 74135.

(2) Ergon Asphalt & Emulsions, Inc. owns Ergon Asphalt Holdings, LLC. The address for Ergon is 2829 Lakeland Drive, Suite 2000, Jackson, Mississippi 39215. Ergon Asphalt Holdings, LLC owns 100% of Blueknight GP Holding, LLC, which owns the membership interest in our General Partner.

(3) Mr. Stallings has pledged as collateral to a bank 62,054 common units and 20,000 Preferred Units.

(4) 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.

(5) 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.

(6) Messrs. Adams, Brooks, Langdon, R. Lampton and W. Lampton are affiliated with Ergon.

(7) Blueknight Energy Holding, Inc. is a subsidiary of Vitol. The address for Vitol is 2925 Richmond Avenue, 11th Floor, Houston, Texas 77098. Blueknight Energy Holding, Inc. previously owned 50% of Blueknight GP Holding, LLC, which owns the membership interest in our General Partner, but this ownership was terminated effective October 6, 2016.

(8) CB-Blueknight, LLC is a subsidiary of Charlesbank. The address for Charlesbank is 200 Clarendon Street, 54th Floor, Boston, Massachusetts. CB-Blueknight, LLC previously owned 50% of Blueknight GP Holding, LLC, which owns the membership interest in our General Partner, but this ownership was terminated effective October 6, 2016.

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(9) Based on a Schedule 13G/A filed January 30, 2018, by MSD Partners, L.P. with the SEC. The filing was made jointly with MSD Torchlight Partners, L.P., MSD Partners (GP), LLC, Glenn R. Fuhrman, John C. Phelan and Marc R. Lisker, and reported that they have shared voting power with respect to 240,000 common units and 1,907,711 Preferred Units. Their address as reported in such Schedule 13G/A is 645 Fifth Avenue, 21st Floor, New York, New York 10022.

(10) Based on Schedules 13G/A filed February 14, 2018, with the SEC by Swank Capital, LLC. The filings were made jointly with Cushing Asset Management, LP and Jerry V. Swank, and report that they have shared voting power with respect to 4,430,929 common units and 2,269,729 Preferred Units. Their address as reported in such Schedules 13G/A is 8117 Preston Road, Suite 440, Dallas, Texas 75225.

(11) Based on a Schedule 13G/A filed February 15, 2018, by Neuberger Berman Group LLC with the SEC. The filing was made jointly with Neuberger Berman Investment Advisers LLC, and reports that they have shared voting power with respect to 5,918,530 common units and shared dispositive power with respect to 6,175,108 common units. Their address as reported in such Schedule 13G/A is 1290 Avenue of the Americas, New York, New York 10104.

(12) Based on a Schedule 13G/A filed January 25, 2018, by DG Capital Management, LLC with the SEC. The filing was made jointly with Dov Gertzulin, and reports that they have shared voting power with respect to 3,175,947 common units. Their address as reported in such Schedule 13G/A is 460 Park Avenue, 22nd Floor, New York, New York 10022.

(13) Based on a Schedule 13G filed February 14, 2018, by Clearbridge Investments, LLC with the SEC. Their address as reported in such Schedule 13G is 620 8th Avenue, New York, New York 10018.

(14) Based on a Schedule 13G filed February 6, 2018, by Oppenheimer Funds, Inc. with the SEC. Their address as reported in such Schedule 13G is 225 Liberty Street, New York, New York 10281.

Securities Authorized for Issuance under Equity Compensation Plans (as of March 1, 2018)
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	702,548	$—	2,387,563
Equity compensation plans not approved by security holders	N/A	N/A	N/A
Total	702,548	$—	2,387,563

(1) Our General Partner has adopted and maintains the LTIP for employees, consultants and directors of our General Partner and its affiliates who perform services for us. An aggregate of 679,943 phantom units that have been granted to our executive officers and other employees remain outstanding and have not yet vested. Excluding phantom unit grants, the responses are as follows: (a) 22,605, (b) $0 and (c) 3,067,506. 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 LTIP, please see "Item 11-Executive Compensation-Compensation Discussion and Analysis-Long-Term Incentive Plan." In addition, on June 23, 2014, our unitholders approved the Unit Purchase Plan. A maximum of 1,000,000 common units may be delivered under the Unit Purchase Plan, subject to adjustment for a recapitalization, split, reorganization or similar event pursuant to the terms of the Unit Purchase Plan. As of March 1, 2018, 170,743 common units had been delivered under the Unit Purchase Plan. For more

information about the Unit Purchase Plan, please see “Item 11-Executive Compensation-Compensation Discussion and Analysis-Unit Purchase 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 Ergon, which also owns 18,312,968 of the 35,125,202 outstanding Preferred Units and 3,049,187 of the 40,310,272 outstanding common units, representing an aggregate 28.3% limited partner interest in us as of March 1, 2018. In addition, our General Partner owns a 1.6% 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 Related Parties and Affiliates

For information regarding material agreements with related parties and affiliates, see Note 13 to our consolidated financial statements.

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:

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- 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 us 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 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,	
	2016	2017

Audit fees(1)	$817,822	$671,164
Audit-related fees(2)	—	—
Tax fees(3)	238,697	299,261
All other fees(4)	—	—

(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 billed for each of the years presented for assurance and related services that are reasonably related to the performance of the annual audit or quarterly reviews.

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(3) Tax fees represent amounts billed for 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 billed for 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.

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PART IV. FINANCIAL INFORMATION

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
2.1	Contribution Agreement, dated July 19, 2016, among Blueknight Energy Partners, L.P., Blueknight Terminal Holding, L.L.C., Ergon Asphalt & Emulsions, Inc., Ergon Terminaling, Inc. and Ergon Asphalt Holdings, LLC (filed as Exhibit 2.1 to the Partnership's Current Report on Form 8-K, filed on July 20, 2016, and incorporated herein by reference).
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 on November 25, 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 on 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 on November 25, 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 on 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 on 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 on 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 on 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 on September 27, 2011, and incorporated herein by reference).
4.6	Registration Rights Agreement, dated October 5, 2016, by and among Blueknight Energy Partners, L.P., Ergon Asphalt & Emulsions, Inc., Ergon Terminaling, Inc. and Ergon Asphalt Holdings, LLC (filed as Exhibit 4.1 to the Partnership's Current Report on Form 8-K, filed on October 5, 2016, and incorporated herein by reference).
4.7	Amended and Restated Registration Rights Agreement, dated December 1, 2017, by and among Blueknight Energy Partners, L.P., Ergon Asphalt & Emulsions, Inc., Ergon Terminaling, Inc. and Ergon Asphalt Holdings, LLC (filed as Exhibit 4.1 to the Partnership's Current Report on Form 8-K, filed on December 1, 2017, and incorporated herein by reference).
10.1#	

	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 on August 18, 2011, and incorporated herein by reference).
10.2#	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).
10.3#	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 (filed as Exhibit 10.13 to the Partnership's Quarterly Report on Form 10-Q, filed on March 14, 2013, and incorporated by reference).
10.4#	Second Amendment to Crude Oil Storage Services Agreement, effective May 1, 2015, by and between BKEP Crude, LLC and Vitol, Inc. (filed as Exhibit 10.1 to the Partnership's Current Report on Form 8-K, filed on January 26, 2015, and incorporated herein by reference).

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10.5	Third Amendment to Crude Oil Storage Services Agreement, dated August 12, 2016 but effective as of May 1, 2017 (filed as Exhibit 10.1 to the Partnership's Current Report on Form 8-K, filed on August 19, 2016, and incorporated herein by reference).
10.6†	Blueknight Energy Partners G.P., L.L.C. Long-Term Incentive Plan (as amended and restated effective April 29, 2014) (filed as Exhibit 10.2 to the Partnership's Current Report on Form 8-K, filed on June 27, 2014, and incorporated herein by reference).
10.7*†	First Amendment to the Blueknight Energy Partners G.P., L.L.C. Long-Term Incentive Plan
10.8†	Form of Phantom Unit Agreement (for pre-2018 grants) (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).
10.9*†	Form of Phantom Unit Agreement (for grants during and after 2018)
10.10†	Form of Director Restricted Common Unit Agreement (for grants during and before 2017) (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).
10.11*†	Form of Director Restricted Common Unit Agreement (for post-2017 grants)
10.12†	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 on October 4, 2012, and incorporated herein by reference).
10.13†	Form of Employment Agreement (filed as Exhibit 10.6 to the Partnership's Registration Statement on Form S-1 (Reg. No. 333-141196), filed on May 25, 2007, and incorporated herein by reference).
10.14†	Form of Indemnification Agreement (filed as Exhibit 10.7 to the Partnership's Registration Statement on Form S-1 (Reg. No. 333-141196), filed on May 25, 2007, and incorporated herein by reference).
10.15†	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 on October 4, 2012, and incorporated herein by reference).
10.16	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).
10.17	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).
10.18†	Blueknight Energy Partners, L.P. Employee Unit Purchase Plan, dated to be effective as of June 23, 2014 (filed as Exhibit 10.1 to the Partnership's Current Report on Form 8-K, filed on June 27, 2014, and incorporated herein by reference).
10.19	Preferred Unit Repurchase Agreement, dated July 19, 2016, among Blueknight Energy Partners, L.P., CB-Blueknight, LLC and Blueknight Energy Holding, Inc. (filed as Exhibit 10.1 to the Partnership's Current Report on Form 8-K, filed on July 20, 2016, and incorporated herein by reference).
10.20	Amended and Restated Credit Agreement, dated as of May 11, 2017, by and among Blueknight Energy Partners, L.P. Wells Fargo Bank, National Association, as Administrative Agent, and the several lenders from time to time party thereto (filed as Exhibit 10.1 to the Partnership's Current Report on Form 8-K, filed May 12, 2017 (Commission File No. 001-33503), and incorporated herein by reference).
10.21#	Storage, Throughput and Handling Agreement, dated October 5, 2016, by and among BKEP Materials, L.L.C., BKEP Terminalling, L.L.C., BKEP Asphalt, L.L.C., and Ergon Asphalt & Emulsions, Inc. (filed as Exhibit 10.1 to the Partnership's Current Report on Form 8-K, filed on October 5, 2016, and incorporated herein by reference).
10.22	Omnibus Agreement, dated October 5, 2016, by and among Ergon Asphalt & Emulsions, Inc., Blueknight Energy Partners G.P., L.L.C., Blueknight Energy Partners, L.P., Blueknight Terminalling, L.L.C., BKEP Materials, L.L.C. and BKEP Asphalt, L.L.C. (filed as Exhibit 10.2 to the Partnership's Current Report on Form

	8-K, filed on October 5, 2016, and incorporated herein by reference).
10.23#	Facilities Lease Agreement, dated May 18, 2009, by and between BKEP Materials, L.L.C, BKEP Asphalt, L.L.C and Ergon Asphalt & Emulsions, Inc. (filed as Exhibit 10.6 to the Partnership's Quarterly Report on Form 10-Q, filed on November 2, 2016, and incorporated herein by reference).
10.24#	Master Facilities Lease Agreement, dated November 11, 2010, by and between BKEP Materials, L.L.C, BKEP Asphalt, L.L.C and Ergon Asphalt & Emulsions, Inc. (filed as Exhibit 10.7 to the Partnership's Quarterly Report on Form 10-Q, filed on November 2, 2016, and incorporated herein by reference).
10.25#	Second Amendment to Master Facilities Lease Agreement, dated July 2, 2012, by and between BKEP Materials, L.L.C, BKEP Asphalt, L.L.C and Ergon Asphalt & Emulsions, Inc. (filed as Exhibit 10.8 to the Partnership's Quarterly Report on Form 10-Q, filed on November 2, 2016, and incorporated herein by reference).

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10.26*	Partial Lease Termination No. 5 to Master Facilities Lease Agreement, dated March 7, 2018, by and between BKEP Materials, L.L.C, BKEP Asphalt, L.L.C and Ergon Asphalt & Emulsions, Inc.
10.27*	Fifth Amendment to Master Facilities Lease Agreement, dated March 7, 2018, by and between BKEP Materials, L.L.C, BKEP Asphalt, L.L.C and Ergon Asphalt & Emulsions, Inc.
21.1*	List of Subsidiaries of Blueknight Energy Partners, L.P.
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, 2017, formatted in XBRL (eXtensible Business Reporting Language): (i) Document and Entity Information; (ii) Consolidated Balance Sheets as of December 31, 2016 and 2017; (iii) Consolidated Statements of Operations for the years ended December 31, 2015, 2016 and 2017; (iv) Consolidated Statement of Changes in Partners' Capital for the years ended December 31, 2015, 2016 and 2017; (v) Consolidated Statements of Cash Flows for the years ended December 31, 2015, 2016 and 2017; and (vi) Notes to Consolidated Financial Statements.

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* Filed herewith.

** Furnished herewith

Certain portions of this exhibit are subject to a request for 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.

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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 8, 2018	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 8, 2018.

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Signature	Title
/s/ Mark A. Hurley Mark A. Hurley	Chief Executive Officer and Director (Principal Executive Officer)
/s/ Alex G. Stallings Alex G. Stallings	Chief Financial Officer and Secretary (Principal Financial Officer)
/s/ James R. Griffin James R. Griffin	Chief Accounting Officer (Principal Accounting Officer)
/s/ Duke R. Ligon Duke R. Ligon	Director
/s/ Steven M. Bradshaw Steven M. Bradshaw	Director
/s/ John A. Shapiro John A. Shapiro	Director
/s/ W.R. “Lee” Adams W.R. “Lee” Adams	Director
/s/ Edward D. Brooks Edward D. Brooks	Director
/s/ Jimmy A. Langdon Jimmy A. Langdon	Director
/s/ Robert H. Lampton Robert H. Lampton	Director
/s/ William W. Lampton William W. Lampton	Director

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Item 16. Form 10-K Summary.

None.

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

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Report of Independent Registered Public Accounting Firm

To the Board of Directors of Blueknight Energy Partners G.P., L.L.C., the general partner of Blueknight Energy Partners, L.P. and unit holders of Blueknight Energy Partners, L.P.

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Blueknight Energy Partners, L.P. and its subsidiaries as of December 31, 2017 and 2016, and the related consolidated statements of operations, changes in partners' capital, and cash flows for each of the three years in the period ended December 31, 2017, including the related notes (collectively referred to as the "consolidated financial statements"). We also have audited the Partnership's internal control over financial reporting as of December 31, 2017 based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Partnership as of December 31, 2017 and 2016, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Partnership did not maintain, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO because a material weakness in internal control over financial reporting related to maintaining effective controls over the presentation of transactions within the consolidated statement of cash flows existed as of that date.

A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the annual or interim financial statements will not be prevented or detected on a timely basis. The material weakness referred to above is described in Management's Report on Internal Control Over Financial Reporting appearing under Item 9A. We considered this material weakness in determining the nature, timing, and extent of audit tests applied in our audit of the 2017 consolidated financial statements, and our opinion regarding the effectiveness of the Partnership's internal control over financial reporting does not affect our opinion on those consolidated financial statements.

Basis for Opinions

The Partnership's management is responsible for these consolidated 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 referred to above. Our responsibility is to express opinions on the Partnership's consolidated financial statements and on the Partnership's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. 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.

Definition and Limitations of Internal Control over Financial Reporting

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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/ PricewaterhouseCoopers LLP

Tulsa, Oklahoma
March 8, 2018

We have served as the Partnership's auditor since 2007.

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

	As of December 31,	
	2016	2017
ASSETS		
Current assets:		
Cash and cash equivalents	$3,304	$2,469
Accounts receivable, net of allowance for doubtful accounts of $49 and $28 at December 31, 2016 and 2017, respectively	7,544	7,589
Receivables from related parties, net of allowance for doubtful accounts of $0 at both dates	1,860	3,070
Prepaid insurance	1,578	2,009
Other current assets	7,934	8,438
Total current assets	22,220	23,575
Property, plant and equipment, net of accumulated depreciation of $292,117 and $316,591 at December 31, 2016 and 2017, respectively	307,334	296,069
Assets held for sale, net of accumulated depreciation of $3,041 at December 31, 2016	4,237	—
Investment in unconsolidated affiliate	20,561	—
Goodwill	4,746	3,870
Debt issuance costs, net	2,050	4,442
Intangibles and other assets, net	14,515	12,913
Total assets	$375,663	$340,869
LIABILITIES AND PARTNERS’ CAPITAL		
Current liabilities:		
Accounts payable	$3,174	$4,439
Accounts payable to related parties	1,053	2,268
Accrued interest payable	413	694
Accrued property taxes payable	2,531	2,432
Unearned revenue	2,350	2,393
Unearned revenue with related parties	383	551
Accrued payroll	6,358	6,119
Other current liabilities	4,279	4,747
Total current liabilities	20,541	23,643
Long-term unearned revenue with related parties	640	1,052
Long-term interest rate swap liabilities	1,947	225
Other long-term liabilities	2,959	3,673
Long-term debt	324,000	307,592
Commitments and contingencies (Note 17)		
Partners’ capital:		
Preferred Units (35,125,202 units issued and outstanding at both dates)	253,923	253,923
Common unitholders (38,003,397 and 40,158,342 units issued and outstanding at December 31, 2016 and 2017, respectively)	471,180	454,358
General partner interest (1.7% and 1.6% interest at December 31, 2016 and 2017, respectively, with 1,225,409 general partner units outstanding at both dates)	(699,527)	(703,597)
Total partners’ capital	25,576	4,684
Total liabilities and partners’ capital	$375,663	$340,869

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

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

	Year ended December 31,		
	2015	2016	2017
Service revenue:			
Third-party revenue	$137,415	$126,215	$113,772
Related-party revenue	39,103	30,211	56,688
Product sales revenue:			
Third-party revenue	3,511	20,968	11,479
Total revenue	180,029	177,394	181,939
Costs and expenses:			
Operating expense	127,974	111,091	123,805
Cost of product sales	3,231	14,130	8,807
General and administrative expense	18,976	20,029	17,112
Asset impairment expense	21,996	25,761	2,400
Total costs and expenses	172,177	171,011	152,124
Gain (loss) on sale of assets	6,137	108	(975)
Operating income	13,989	6,491	28,840
Other income (expense):			
Equity earnings in unconsolidated affiliate	3,932	1,483	61
Gain on sale of unconsolidated affiliate	—	—	5,337
Interest expense (net of capitalized interest of $184, $41, and $18, respectively)	(11,202)	(12,554)	(14,027)
Income (loss) before income taxes	6,719	(4,580)	20,211
Provision for income taxes	323	260	166
Net income (loss)	$6,396	$(4,840)	$20,045
Allocation of net income (loss) for calculation of earnings per unit:			
General partner interest in net income	$554	$433	$944
Preferred interest in net income	$21,564	$25,824	$25,115
Net loss available to limited partners	$(15,722)	$(31,097)	$(6,014)
Basic and diluted net loss per common unit	$(0.47)	$(0.87)	$(0.15)
Weighted average common units outstanding - basic and diluted	32,945	35,093	38,342

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

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

	Common Unitholders	Preferred Unitholders	General Partner Interest	Total Partners' Capital
Balance, December 31, 2014	$ 525,767	$ 204,599	$ (610,410)	$ 119,956
Net income (loss)	(15,281)	21,564	113	6,396
Equity-based incentive compensation	2,095	—	36	2,131
Profits interest contribution	—	—	150	150
Distributions	(18,943)	(21,564)	(1,093)	(41,600)
Proceeds from sale of 30,075 common units pursuant to the Employee Unit Purchase Plan	186	—	—	186
Balance, December 31, 2015	$ 493,824	$ 204,599	$ (611,204)	$ 87,219
Net income (loss)	(30,004)	24,939	225	(4,840)
Equity-based incentive compensation	2,051	—	36	2,087
Profits interest contribution	—	—	923	923
Distributions	(20,960)	(24,939)	(1,320)	(47,219)
Capital contributions	—	—	2,384	2,384
Proceeds from sale of 3,795,000 common units, net of underwriters' discount and offering expenses of $1.5 million	20,931	—	—	20,931
Proceeds from sale of 71,807 common units pursuant to the Employee Unit Purchase Plan	338	—	—	338
Repurchase of 13,335,390 Preferred Units	—	(95,348)	—	(95,348)
Proceeds from issuance of 18,312,968 Preferred Units	—	144,672	—	144,672
Proceeds from issuance of 847,457 common units	5,000	—	—	5,000
Proceeds from issuance of 97,654 general partner units	—	—	680	680
Consideration paid in excess of historical cost of assets acquired from Ergon	—	—	(91,251)	(91,251)
Balance, December 31, 2016	$ 471,180	$ 253,923	$ (699,527)	$ 25,576
Net income (loss)	(6,009)	25,116	938	20,045
Equity-based incentive compensation	1,424	—	27	1,451
Distributions	(22,633)	(25,116)	(1,414)	(49,163)
Capital contributions	—	—	104	104
Proceeds from sale of 53,079 common units pursuant to the Employee Unit Purchase Plan	240	—	—	240
Value of 1,898,380 common units issued for acquisitions	10,156	—	—	10,156
Consideration paid in excess of historical cost of assets acquired from Ergon	—	—	(3,725)	(3,725)
Balance, December 31, 2017	$ 454,358	$ 253,923	$ (703,597)	$ 4,684

The accompanying notes are an integral part of this consolidated financial statement.

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

	Year ended December 31,		
	2015	2016	2017
Cash flows from operating activities:			
Net income (loss)	$6,396	$(4,840)	$20,045
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Provision for uncollectible receivables from third parties	(184)	15	(21)
Provision for uncollectible receivables from related parties	—	(229)	—
Depreciation and amortization	27,228	30,820	31,139
Impairment of intangible assets	7,498	—	1,107
Amortization and write-off of debt issuance costs	884	1,107	1,816
Unrealized loss (gain) related to interest rate swaps	469	(1,156)	(1,790)
Fixed asset impairment charge	14,498	25,761	1,293
Loss (gain) on sale of assets	(6,137)	(108)	975
Gain on sale of unconsolidated affiliate	—	—	(5,337)
Equity-based incentive compensation	2,131	2,087	1,451
Equity earnings in unconsolidated affiliate	(3,932)	(1,483)	(61)
Distributions from unconsolidated affiliate	4,313	—	—
Gain related to investments	(267)	—	—
Changes in assets and liabilities:			
Decrease (increase) in accounts receivable	538	1,138	(24)
Decrease (increase) in receivables from related parties	472	213	(1,210)
Decrease in prepaid insurance	3,998	3,008	2,507
Decrease (increase) in other current assets	(579)	237	(983)
Decrease (increase) in other assets	(1,485)	(498)	84
Increase (decrease) in accounts payable	(792)	(237)	952
Increase in payables to related parties	—	1,053	749
Increase (decrease) in accrued interest payable	(42)	222	281
Increase (decrease) in accrued property taxes	727	(242)	(72)
Increase (decrease) in unearned revenue	2,075	(1,568)	898
Increase (decrease) in unearned revenue from related parties	(189)	187	580
Increase (decrease) in accrued payroll	743	(905)	(239)
Increase (decrease) in other accrued liabilities	2,169	(1,733)	354
Net cash provided by operating activities	60,532	52,849	54,494
Cash flows from investing activities:			
Acquisition of assets from Ergon	—	(122,572)	—
Acquisitions	(20,951)	(18,989)	—
Capital expenditures	(41,609)	(19,995)	(18,715)
Proceeds from sale of assets	14,687	1,993	9,297
Distributions from unconsolidated affiliate	922	—	—
Proceeds from sale of investments	2,346	—	—
Proceeds from sale of unconsolidated affiliate	—	—	26,489
Net cash provided by (used in) investing activities	(44,605)	(159,563)	17,071
Cash flows from financing activities:			
Payment on insurance premium financing agreement	(3,286)	(3,425)	(2,965)
Debt issuance costs	—	(956)	(4,208)
Borrowings under credit agreement	112,000	170,000	378,592

Payments under credit agreement	(83,000)	(91,000)	(395,000)
Proceeds from issuance of common units, net of offering costs	186	26,269	240
Proceeds from issuance of Preferred Units	—	144,672	—
Proceeds from issuance of general partner units	—	680	—
Repurchase of Preferred Units	—	(95,348)	—
Capital contributions	—	2,384	104
Capital contribution related to profits interest	150	923	—
Distributions	(41,600)	(47,219)	(49,163)
Net cash provided by (used in) financing activities	(15,550)	106,980	(72,400)

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

	Year ended December 31,		
	2015	2016	2017
Net increase (decrease) in cash and cash equivalents	377	266	(835)
Cash and cash equivalents at beginning of period	2,661	3,038	3,304
Cash and cash equivalents at end of period	$3,038	$3,304	$2,469
Supplemental disclosure of cash flow information:			
Assets acquired through non-cash equity issuance	$—	$—	$10,156
Increase (decrease) in accounts payable related to purchases of property, plant and equipment	$(1,598)	$(1,825)	$779
Increase in accrued liabilities related to insurance premium financing agreement	$3,813	$3,189	$2,938
Cash paid for interest, net of amounts capitalized	$9,915	$12,404	$13,732
Cash paid for income taxes	$412	$282	$158

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

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

1. ORGANIZATION AND NATURE OF BUSINESS

Blueknight Energy Partners, L.P. and subsidiaries (collectively, the “Partnership”) is a publicly traded master limited partnership with operations in 27 states. The Partnership provides integrated terminalling, gathering and transportation services for companies engaged in the production, distribution and marketing of liquid asphalt and crude oil. The Partnership manages its operations through four operating segments: (i) asphalt terminalling services, (ii) crude oil terminalling services, (iii) crude oil pipeline services and (iv) crude oil trucking and producer field 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 2007 as a Delaware master limited partnership initially to own, operate and develop a diversified portfolio of complementary midstream energy assets.

On October 5, 2016, the Partnership completed the following transactions (the “Ergon Transactions”): (i) a subsidiary of Ergon, Inc. (together with its subsidiaries, “Ergon”) purchased 100% of the outstanding voting stock of Blueknight GP Holding, L.L.C., which owns 100% of the capital stock of the Partnership’s general partner, Blueknight Energy Partners G.P., L.L.C., pursuant to a Membership Interest Purchase Agreement dated July 19, 2016, among CB-Blueknight, LLC, an indirect wholly-owned subsidiary of Charlesbank, Blueknight Energy Holding, Inc., an indirect wholly-owned subsidiary of Vitol Holding B.V. (together with its affiliates and subsidiaries “Vitol”), and Ergon Asphalt Holdings, LLC, a wholly-owned subsidiary of Ergon (the “Ergon Change of Control”); (ii) Ergon contributed nine asphalt terminals plus $22.1 million in cash in return for total consideration of approximately $144.7 million, which consisted of the issuance of 18,312,968 of Preferred Units in a private placement; and (iii) Ergon acquired an aggregate of $5.0 million of common units for cash in a private placement, pursuant to a Contribution Agreement between the Partnership and Ergon. In addition, the Partnership repurchased 6,667,695 Preferred Units from each Vitol and Charlesbank for an aggregate purchase price of approximately $95.3 million. Vitol and Charlesbank each retained 2,488,789 Preferred Units upon completion of these transactions

The Partnership’s acquisition of nine asphalt terminals from Ergon on October 5, 2016, was accounted for as a transaction among entities under common control. As a result, the Partnership recorded the acquired assets at Ergon’s historical cost of $31.3 million, net of accumulated depreciation of $63.0 million. The $91.3 million of consideration in excess of Ergon’s historical net book value was recorded as a deemed distribution to the Partnership’s general partner and is reflected as “Consideration paid in excess of historical cost of assets acquired from Ergon” on the Partnership’s consolidated statement of changes in partners’ capital.

2. BASIS OF CONSOLIDATION AND PRESENTATION

The accompanying consolidated financial statements and related notes present and discuss the Partnership’s consolidated financial position as of December 31, 2016 and 2017, and the consolidated results of the Partnership’s operations, cash flows and changes in partners’ capital for the years ended December 31, 2015, 2016 and 2017. The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (“GAAP”). All significant intercompany accounts and transactions have been eliminated in the preparation of the accompanying consolidated financial statements. Certain reclassifications have been made to the prior period consolidated financial statements to conform to the current period presentation.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

USE OF ESTIMATES - The preparation of financial statements in conformity with GAAP 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 - Cash and cash equivalents includes cash and all investments with original maturities 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 asphalt terminalling services, crude oil pipeline services and crude oil trucking and producer field services activities. Accounts receivable included in the consolidated balance sheets are reflected net of the allowance for doubtful accounts of less than $0.1 million at both December 31, 2016 and 2017.

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 values of the assets are 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 consolidated 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 liquid asphalt cement and residual fuel oil terminalling assets are abandoned (see Note 17). 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.

During the year ended December 31, 2015, the Partnership recognized fixed asset impairment charges of $12.6 million, $1.4 million and $0.5 million related to the East Texas pipeline system, a portion of the Mid-Continent pipeline system and the West Texas trucking stations, respectively.

During the year ended December 31, 2016, the Partnership recognized fixed asset impairment charges of $25.8 million, primarily due to impairment recognized on the Knight Warrior pipeline project and the East Texas pipeline system. The Knight Warrior pipeline project was canceled due to continued low rig counts in the Eaglebine/Woodbine area coupled with lower production volumes, competing projects and the overall impact of the decreased market price of crude oil. Consequently, shipper commitments related to the project were canceled and an impairment expense of $22.6 million was recognized during the year ended December 31, 2016.

During the year ended December 31, 2017, the Partnership recognized fixed asset impairment charges of $1.2 million related to the producer field services business, primarily operated in the Texas panhandle.

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 charges were recognized during the years ended December 31, 2015 or 2016, with respect to intangible assets. During the year ended December 31, 2017, the Partnership recognized intangible asset impairment charges of $0.2 million on customer relationships related to the producer field services business, primarily operated in the Texas panhandle.

EQUITY METHOD INVESTMENTS - The Partnership’s approximate 30% ownership investment in Advantage Pipeline, L.L.C. (“Advantage Pipeline”), over which the Partnership had significant influence but not control, was accounted for by the equity method. The Partnership did not consolidate any part of the assets or liabilities of its equity method investee. On April 3, 2017, Advantage Pipeline was acquired by a joint venture formed by affiliates of Plains All American Pipeline, L.P.

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and Noble Midstream Partners LP. The Partnership's share of net income or loss is reflected as one line item on the Partnership's consolidated statements of operations entitled "Equity earnings in unconsolidated affiliate" and increased or decreased, as applicable, the carrying value of the Partnership's investment in the unconsolidated affiliate on the consolidated balance sheets. Distributions to the Partnership reduced the carrying value of its investment and are reflected in the Partnership's consolidated statements of cash flows in the line item "Distributions from unconsolidated affiliate." In turn, contributions increased the carrying value of the Partnership's investment and were reflected in the Partnership's consolidated statements of cash flows in investing activities.

DEBT ISSUANCE COSTS - Costs incurred in connection with the issuance of long-term debt related to the Partnership's credit agreement 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.

INVESTMENTS - In November 2014, the Partnership received 30,393 Class A Common Units of SemCorp in connection with the settlement of two unsecured claims the Partnership filed in connection with SemCorp's predecessor's bankruptcy filing in 2008. The fair market value of these units on the date of receipt was $2.5 million. In March 2015, the Partnership sold all of these units for a total of $2.3 million.

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 in December for impairment or 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 its (i) asphalt terminalling services, (ii) crude oil terminalling services, (iii) crude oil pipeline services and (iv) crude oil trucking and producer field services. If the fair value of a reporting unit exceeds its carrying amount, goodwill of the reporting unit is not considered to be 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 the Partnership's 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).

Changes in the carrying amount of goodwill are summarized below for the periods indicated (in thousands):

	Asphalt Terminalling Services	Crude Oil Pipeline Services	Crude Oil Trucking and Producer Field Services	Total
Balance, December 31, 2014	$ —	$ 6,340	$ 876	$ 7,216
Acquisition	3,511	1,158	—	4,669
Impairment	—	(7,498)	—	(7,498)
Balance, December 31, 2015	$ 3,511	$ —	$ 876	$ 4,387
Acquisition	359	—	—	359
Balance, December 31, 2016	$ 3,870	$ —	$ 876	$ 4,746
Impairment	—	—	(876)	(876)
Balance, December 31, 2017	$ 3,870	$ —	$ —	$ 3,870

During the fourth quarter of 2015, impairment testing indicated that the fair value of the crude oil pipeline services reporting unit was less than the carrying value due to declining volumes, and the Partnership recognized impairment of goodwill of $7.5 million related to this reporting unit. During the fourth quarter of 2017, impairment testing indicated that the fair value of the crude oil trucking and producer field services reporting unit was less than the carrying value based on the estimated market value of the producer field services business, and the Partnership recognized impairment of goodwill of $0.9 million related to this reporting unit. Impairment testing indicated there was no impairment of goodwill in 2016.

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 had no such loss contingencies as of December 31, 2016. The Partnership had loss contingencies related to environmental matters of $0.1 million as of December 31, 2017.

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

Terminalling revenues consist of (i) 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 (ii) 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 asphalt products or crude oil exits the terminal and 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 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 services are performed.

Product sales revenues are comprised of (i) revenues recognized for the sale of crude oil to the Partnership's customers that it purchases at production leases and (ii) revenue recognized in buy/sell transactions with the Partnership's customers. Product sales revenue is recognized for products upon delivery and when the customer assumes the risks and rewards of ownership.

Fuel surcharge revenues are comprised of revenues recognized for the reimbursement of fuel and power consumed to operate the Partnership's asphalt product 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, deductions and tax credits generated by the Partnership flow through to the unitholders of the Partnership and are subject to income tax at the individual partner level. The Partnership is subject to the Texas state franchise (margin) tax, and the earnings associated with the Partnership's taxable subsidiary are subject to federal and state income taxes. The Partnership has estimated its liability related to these taxes to be $0.3 million for each of the years ended December 31, 2015 and 2016, and $0.2 million for the year ended December 31, 2017. This liability is reflected on the Partnership's consolidated statements of operations as "Provision for income taxes". See Note 21 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. Effective April 29, 2014, the Partnership's unitholders approved an amendment to the LTIP to increase the number of common units reserved for issuance under the incentive plan to 4.1 million common units, subject to adjustment for certain events. 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 LTIP from its inception through December 31, 2017, 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 sheets 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 the consolidated statements of operations.

4. ACQUISITIONS

On December 1, 2017, the Partnership acquired an asphalt terminalling facility in Bainbridge, Georgia, from Ergon Asphalt & Emulsions, Inc. and Ergon Terminaling, Inc., both subsidiaries of Ergon, for a total purchase price of $10.2 million, consisting of 1,898,380 common units representing limited partner interests in the Partnership. The acquisition was accounted for as a transaction among entities under common control. As a result, the Partnership recorded the acquired assets at Ergon's historical cost of $6.4 million, net of accumulated depreciation of $7.9 million. The $3.7 million of consideration in excess of Ergon's historical net book value was recorded as a deemed distribution to the Partnership's general partner and is reflected as "Consideration paid in excess of historical cost of assets acquired from Ergon" on the Partnership's consolidated statement of changes in partners' capital.

On October 5, 2016, as part of the Ergon Transaction, the Partnership acquired nine asphalt terminals from Ergon. which accounted for as a transaction among entities under common control. As a result, the Partnership recorded the acquired assets at Ergon's historical cost of $31.3 million, net of accumulated depreciation of $63.0 million. The $91.3 million of consideration in excess of Ergon's historical net book value was recorded as a deemed distribution to the Partnership's general partner and is reflected as "Consideration paid in excess of historical cost of assets acquired from Ergon" on the Partnership's consolidated statement of changes in partners' capital.

In February 2016, the Partnership acquired two asphalt terminalling facilities located in Virginia and North Carolina from a third party for $19.0 million.

In May 2015, the Partnership acquired an asphalt terminalling facility in Wyoming from a third party for $13.9 million. In November 2015, the Partnership acquired a 75-mile pipeline system and related crude oil marketing business in southern Oklahoma for $7.0 million from a third party.

5. EQUITY METHOD INVESTMENT

On April 3, 2017, Advantage Pipeline was acquired by a joint venture formed by affiliates of Plains All American Pipeline, L.P. and Noble Midstream Partners LP. The Partnership received cash proceeds at closing from the sale of its approximate 30% equity ownership interest in Advantage Pipeline of approximately $25.3 million and recorded a gain on the sale of the investment of $4.2 million. Approximately 10% of the gross sale proceeds were held in escrow, subject to certain post-closing settlement terms and conditions. The Partnership received approximately $1.1 million of the funds held in escrow in August 2017. The Partnership received approximately $2.2 million for its pro rata portion of the remaining net escrow proceeds in January 2018. The Partnership's proceeds were used to prepay revolving debt (without a commitment reduction). The operating and administrative services agreement to which the Partnership and Advantage Pipeline were parties and under which the Partnership operated the 70-mile, 16-inch Advantage crude oil pipeline, located in the southern Delaware Basin in Texas, was terminated at closing. The Partnership and the Plains/Noble joint venture entered into a short-term transition services agreement under which the Partnership provided certain services through August 1, 2017, when the agreement was terminated.
Summarized financial information for Advantage Pipeline is set forth in the tables below for the periods indicated in which the Partnership held the investment in Advantage Pipeline (in thousands):

	As of December 31, 2016
Balance sheet	
Current assets	$ 2,075
Noncurrent assets	89,065
Total assets	$ 91,140

Current liabilities	1,327
Long-term liabilities	20,910
Member's equity	68,903
Total liabilities and member's equity	$ 91,140

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	Year ended December 31,		Period ended April 3,
	2015	2016	2017
Income statements			
Operating revenues	$26,398	$17,091	$3,150
Operating expenses	$3,059	$2,776	$465
Net income	$14,909	$5,434	$187

6. RESTRUCTURING CHARGES

During the fourth quarter of 2015, the Partnership recognized certain restructuring charges in its crude oil trucking and producer field services segment pursuant to an approved plan to exit the trucking market in West Texas. The following restructuring charges were accrued as of December 31, 2015, and reported in operating expense in the Partnership's consolidated statement of operations for the year ended December 31, 2015:

	Year ended December 31, 2015 (in thousands)
Severance charges	$ 315
Lease payments related to operating leases for idled equipment	1,250
Total restructuring costs	$ 1,565

Changes in the accrued amounts pertaining to the above charges are summarized as follows:

	Year ended December 31,		
	2015	2016	2017
	(in thousands)		
Beginning balance	$—	$1,565	$474
Charged to expense	1,565	—	—
Cash payments	—	1,091	188
Ending balance	$1,565	$474	$286

The remaining accrual relates to lease payments that will be paid over the remaining lease terms, which extend through July 2019.

7. PROPERTY, PLANT AND EQUIPMENT

	Estimated Useful Lives (Years)	As of December 31,	
		2016	2017
		(dollars in thousands)	
Land	N/A	$25,863	$24,776
Land improvements	10-20	6,698	6,787
Pipelines and facilities	5-30	165,293	166,004
Storage and terminal facilities	10-35	347,656	370,056
Transportation equipment	3-10	12,391	3,293
Office property and equipment and other	3-20	35,578	32,011

Pipeline linefill and tank bottoms	N/A	3,234	3,233
Construction-in-progress	N/A	2,738	6,500
Property, plant and equipment, gross		599,451	612,660
Accumulated depreciation		(292,117)	(316,591)
Property, plant and equipment, net		$307,334	$296,069

Depreciation expense for the years ended December 31, 2015, 2016 and 2017 was $27.0 million, $29.6 million and $29.9 million, respectively. During the year ended December 31, 2015, the Partnership recorded fixed asset impairment expense of $14.0 million related to its crude oil pipeline services reporting unit and $0.5 million related to its crude oil trucking and field services reporting unit. During the year ended December 31, 2016, the Partnership recorded fixed asset impairment expense of $25.8 million, primarily due to an impairment recognized on the Knight Warrior pipeline project and the East Texas pipeline system. During the year ended December 31, 2017, the Partnership recorded fixed asset impairment expense of $1.2 million related to the crude oil trucking and field services reporting unit.

Included in assets held for sale on the consolidated balance sheets as of December 31, 2016, is the East Texas pipeline system, with a net book value of $4.2 million. On April 18, 2017, the Partnership sold its East Texas pipeline system. The Partnership received cash proceeds at closing of approximately $4.8 million and recorded a gain of less than $0.1 million. The Partnership used the proceeds received at closing to prepay revolving debt (without a commitment reduction).

8. INTANGIBLES AND OTHER ASSETS, NET

Other assets, net of accumulated amortization, consist of the following:

	As of December 31,	
	2016	2017
	(in thousands)	
Customer relationships	$12,579	$12,221
Deferred charges related to pipeline connection agreements	2,653	2,716
Deposits	435	302
Prepaid insurance	428	353
Other prepaid expenses	24	103
Intangibles and other assets, gross	16,119	15,695
Accumulated amortization of intangible assets	(1,604)	(2,782)
Intangibles and other assets, net	$14,515	$12,913

Amortization expense related to intangibles for the years ended December 31, 2015, 2016 and 2017 was $0.2 million, $1.2 million and $1.3 million, respectively. The estimated aggregate future amortization expense on amortizable intangible assets currently owned by the Partnership is as follows (in thousands):

For year ending:	
December 31, 2018	$1,314
December 31, 2019	1,269
December 31, 2020	1,267
December 31, 2021	1,267
December 31, 2022	1,267
Thereafter	5,771
Total estimated aggregate amortization expense	$12,155

Customer relationships include $8.4 million related to the acquisition of asphalt facilities in February 2016, $3.5 million related to the acquisition of a pipeline and crude oil marketing business in November 2015 and $0.3 million related to the acquisition of a producer field services business in December 2010. The customer relationships are being amortized over a range of 4 to 20 years.

During the year ended December 31, 2017, the Partnership recognized intangible asset impairment charges of $0.2 million on customer relationships related to the producer field services business, primarily operated in the Texas panhandle.

9. DEBT

On May 11, 2017, the Partnership entered into an amended and restated credit agreement which consists of a $450.0 million revolving loan facility.

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As of March 1, 2018, approximately $308.6 million of revolver borrowings and $1.5 million of letters of credit were outstanding under the credit agreement, leaving the Partnership with available capacity of approximately $139.9 million for additional revolver borrowings and letters of credit under the credit agreement, although the Partnership's ability to borrow such funds may be limited by the financial covenants in the credit agreement. The proceeds of loans made under the amended and restated credit agreement may be used for working capital and other general corporate purposes of the Partnership. All references herein to the credit agreement on or after May 11, 2017, refer to the amended and restated credit agreement.

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.

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 $600.0 million for all revolving loan commitments under the credit agreement.

The credit agreement will mature on May 11, 2022, and all amounts outstanding under the credit agreement will become due and payable on such date. The credit agreement requires mandatory prepayments of amounts outstanding thereunder with the net proceeds from certain asset sales, property or casualty insurance claims and condemnation proceedings, unless the Partnership reinvests such proceeds in accordance with the credit agreement, but these mandatory prepayments will not require any reduction of the lenders' commitments under the credit agreement.

Borrowings under the credit agreement bear interest, at the Partnership's option, at either the reserve-adjusted eurodollar rate (as defined in the credit agreement) plus an applicable margin which ranges from 2.0% to 3.0% or the alternate base rate (the highest of the agent bank's prime rate, the federal funds effective rate plus 0.5% and the 30-day eurodollar rate plus 1.0%) plus an applicable margin which ranges from 1.0% to 2.0%. 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 ranging from 0.375% to 0.5% on the unused commitments under the credit agreement. The applicable margins for the Partnership's interest rate, the letters of credit fee and the commitment fee vary quarterly based on the Partnership's consolidated total leverage ratio (as defined in the credit agreement, being generally computed as the ratio of consolidated total debt to consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges).

The credit agreement includes financial covenants which are tested on a quarterly basis, based on the rolling four-quarter period that ends on the last day of each fiscal quarter.

Prior to the date on which the Partnership issues qualified senior notes in an aggregate principal amount (when combined with all other qualified senior notes previously or concurrently issued) that equals or exceeds $200.0 million, the maximum permitted consolidated total leverage ratio is 4.75 to 1.00; provided that the maximum permitted consolidated total leverage ratio will be 5.25 to 1.00 for certain quarters based on the occurrence of a specified acquisition (as defined in the Partnership's credit agreement, but generally being an acquisition for which the aggregate consideration is $15.0 million or more). The acquisition of the nine asphalt terminals from Ergon in 2016 qualified as a specified acquisition.

From and after the date on which the Partnership issues qualified senior notes in an aggregate principal amount (when combined with all other qualified senior notes previously or concurrently issued) that equals or exceeds $200.0 million, the maximum permitted consolidated total leverage ratio is 5.00 to 1.00; provided that from and after the fiscal quarter ending immediately preceding the fiscal quarter in which a specified acquisition occurs, to and including the last day of the second full fiscal quarter following the fiscal quarter in which such acquisition occurred, the maximum permitted consolidated total leverage ratio is 5.50 to 1.00.

The maximum permitted consolidated senior secured leverage ratio (as defined in the credit agreement, but generally computed as the ratio of consolidated total secured debt to consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges) is 3.50 to 1.00, but this covenant is only tested from and after the date on which the Partnership issues qualified senior notes in an aggregate principal amount (when combined with all other qualified senior notes previously or concurrently issued) that equals or exceeds $200.0 million.

The minimum permitted consolidated interest coverage ratio (as defined in the credit agreement, but generally computed as the ratio of consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges to consolidated interest expense) is 2.50 to 1.00.

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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 certain indebtedness, or prepay certain indebtedness;
- engage in transactions with affiliates;
- enter into certain hedging contracts;
- enter into certain burdensome agreements;
- change the nature of the Partnership's business; and
- make certain amendments to the Partnership's partnership agreement.

At December 31, 2017, the Partnership's consolidated total leverage ratio was 4.63 to 1.00 and the consolidated interest coverage ratio was 4.76 to 1.00. The Partnership was in compliance with all covenants of its credit agreement as of December 31, 2017.

The credit agreement permits the Partnership to make quarterly distributions of available cash (as defined in the Partnership's partnership agreement) to unitholders so long as no default or event of default exists under the credit agreement on a pro forma basis after giving effect to such distribution. The Partnership is currently allowed to make distributions to its unitholders in accordance with this covenant; 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 Board 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 11 for additional information regarding distributions.

In addition to other customary events of default, the credit agreement includes an event of default if:

(i) the general partner ceases to own 100% of the Partnership's general partner interest or ceases to control the Partnership;

(ii) Ergon ceases to own and control 50.0% or more of the membership interests of the general partner; or

(iii) during any period of 12 consecutive months, a majority of the members of the Board of the general partner ceases to be composed of individuals:

(A) who were members of the Board on the first day of such period;

(B) whose election or nomination to the Board was approved by individuals referred to in clause (A) above constituting at the time of such election or nomination at least a majority of the Board; or

(C) whose election or nomination to the Board was approved by individuals referred to in clauses (A) and (B) above constituting at the time of such election or nomination at least a majority of the Board,

provided that any changes to the composition of individuals serving as members of the Board approved by Ergon will not cause an event of default.

If an event of default relating to bankruptcy or other insolvency events occurs with respect to the general partner or the Partnership, 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.

Upon the execution of the amended and restated credit agreement, the Partnership expensed $0.7 million of debt issuance costs related to the prior revolving loan facility, leaving a remaining balance of $0.9 million ascribed to those lenders with commitments under both the prior and the amended and restated credit agreement. During the year ended December 31, 2015, the Partnership capitalized no debt issuance costs. During the years ended December 31, 2016 and 2017, the Partnership capitalized debt issuance costs related to its credit agreement of $1.0 million and $4.2 million, respectively. The debt issuance costs are being amortized over the term of the credit agreement. Interest expense related to debt issuance cost amortization for

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the year ended December 31, 2015, was $0.9 million. Interest expense related to debt issuance cost amortization for each of the years ended December 31, 2016 and 2017 was $1.1 million.

During the years ended December 31, 2015, 2016 and 2017, the weighted average interest rate under the Partnership's credit agreement, excluding the $0.7 million of debt issuance costs related to the prior credit agreement that were expensed during the year ended December 31, 2017, was 3.37%, 3.95% and 4.43%, respectively, resulting in interest expense of approximately $7.9 million, $11.2 million and $13.8 million, respectively.

During the year ended December 31, 2015, the Partnership capitalized interest of $0.2 million. During each of the years ended December 31, 2016 and 2017, the Partnership capitalized interest of less than $0.1 million.

The Partnership is exposed to market risk for changes in interest rates related to its credit agreement. Interest rate swap agreements are used to manage a portion of the exposure related to changing interest rates by converting floating-rate debt to fixed-rate debt. As of December 31, 2016 and 2017, the Partnership had interest rate swaps with notional amounts totaling $200.0 million to hedge the variability of its LIBOR-based interest payments, with half maturing on June 28, 2018, and the other half maturing on January 28, 2019. During the years ended December 31, 2015, 2016 and 2017, the Partnership recorded swap interest expense of $2.9 million, $2.5 million and $1.3 million, respectively. The interest rate swaps do not receive hedge accounting treatment under ASC 815 - Derivatives and Hedging.

The following provides information regarding the Partnership's assets and liabilities related to its interest rate swap agreements as of the periods indicated (in thousands):

Derivatives Not Designated as Hedging Instruments	Balance Sheet Location	Fair Values of Derivative Instruments	
		December 31, 2016	December 31, 2017
Interest rate swap assets - current	Other current assets	$—	$ 68
Interest rate swap liabilities - noncurrent	Long-term interest rate swap liabilities	$1,947	$ 225

Changes in the fair value of the interest rate swaps are reflected in the consolidated statements of operations as follows (in thousands):

Derivatives Not Designated as Hedging Instruments	Location of Gain (Loss) Recognized in Net Income on Derivatives	Amount of Gain (Loss) Recognized in Net Income on Derivatives Year ended December 31,		
		2015	2016	2017
Interest rate swaps	Interest expense, net of capitalized interest	$(469)	$1,156	$1,790

10. 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 Partnership's 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 per common unit (in thousands, except per unit data):

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	Year ended December 31,		
	2015	2016	2017
Net income (loss)	$6,396	$(4,840)	$20,045
General partner interest in net income	554	433	944
Preferred interest in net income	21,564	25,824	25,115
Net loss available to limited partners	$(15,722)	$(31,097)	$(6,014)
Basic and diluted weighted average number of units:			
Common units	32,945	35,093	38,342
Restricted and phantom units	685	803	862
Total units	33,630	35,896	39,204
Basic and diluted net loss per common unit	$(0.47)	$(0.87)	$(0.15)

11. PARTNERS' CAPITAL AND DISTRIBUTIONS

On December 1, 2017, the Partnership issued 1,898,380 common units to Ergon in a private placement for $10.2 million in exchange for an asphalt terminalling facility in Bainbridge, Georgia. See additional detail in Note 4.

On October 5, 2016, the Partnership completed the following transactions:

- issued 847,457 common units to Ergon in a private placement for $5.0 million;
- repurchased 6,667,695 Preferred Units from each Vitol and Charlesbank for an aggregate purchase price of approximately $95.3 million, leaving both Vitol and Charlesbank with 2,488,789 Preferred Units upon completion of these transactions; and
- issued 18,312,968 Preferred Units to Ergon for $144.7 million, as well as 97,654 general partner units to Ergon for $0.7 million.

On July 26, 2016, the Partnership issued and sold 3,795,000 common units for a public offering price of $5.90 per unit, resulting in proceeds of approximately $20.9 million, net of underwriters' discount and offering expenses of $1.5 million.

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 as follows:

- first, 98.4% to the preferred unitholders and 1.6% to its general partner until the Partnership distributes for each Preferred Unit an amount equal to the Preferred Units quarterly distribution amount discussed below;
- second, 98.4% to the preferred unitholders and 1.6% to its general partner until the Partnership distributes for each Preferred Unit an amount equal to any Preferred Units cumulative distribution arrearage; and
- thereafter, 98.4% to the common unitholders and 1.6% to its general partner until the common unitholders receive the minimum quarterly distribution of $0.11 per unit.

The Preferred Units are convertible at the holders' option into common units. Holders of the Preferred Units are entitled to quarterly distributions of $0.17875 per unit per quarter. 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.

The general partner receives incentive distribution rights. Incentive distribution rights represent the right to receive an increasing percentage (13.0%, 23.0% and 48.0%) of quarterly distributions of available cash from operating surplus after the minimum quarterly distribution and the target distribution levels have been achieved. The 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. If for any quarter:

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- the Partnership has distributed available cash from operating surplus to the holders of our Preferred Units in an amount equal to the Preferred Units quarterly distribution amount;
- the Partnership has 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 Preferred Units quarterly distribution amount; and
- the Partnership has distributed available cash from operating surplus to the common unitholders and Class B unitholders in an amount equal to the minimum quarterly distribution;

then the partnership agreement requires that the Partnership distribute any additional available cash from operating surplus for that quarter among the unitholders and the general partner in the following manner:

- first, 98.4% to all unitholders holding common units or Class B units, pro rata, and 1.6% to the general partner, until each unitholder receives a total of $0.1265 per unit for that quarter (the "first target distribution");
- second, 85.4% to all unitholders holding common units or Class B units, pro rata, and 14.6% to the general partner, until each unitholder receives a total of $0.1375 per unit for that quarter (the "second target distribution");
- third, 75.4% to all unitholders holding common units or Class B units, pro rata, and 24.6% to the general partner, until each unitholder receives a total of $0.1825 per unit for that quarter (the "third target distribution"); and
- thereafter, 50.4% to all unitholders holding common units or Class B units, pro rata, and 49.6% to the general partner.

Distributions are also paid to the holders of restricted units and phantom units as disclosed in Note 14.

The Partnership paid the following distributions on the Preferred Units during the years ended December 31, 2015, 2016 and 2017 (in thousands):

Year Paid	Periods Covered	Total	Paid to Preferred Unitholders	Paid to General Partner
2015	Quarters ending December 31, 2014, March 31, 2015, June 30, 2015 and September 30, 2015	$21,949	$ 21,563	$ 385
2016	Quarters ending December 31, 2015, March 31, 2016, June 30, 2016 and September 30, 2016	$22,837	$ 22,449	$ 388
2017	Quarters ending December 31, 2016, March 31, 2017, June 30, 2017 and September 30, 2017	$25,534	$ 25,115	$ 420

In addition, on January 23, 2018, the Board approved a cash distribution of $0.17875 per outstanding Preferred Unit for the quarter ending December 31, 2017. The Partnership paid this distribution on the Preferred Units on February 14, 2018, to unitholders of record as of February 2, 2018. The total distribution was approximately $6.4 million, with approximately $6.3 million and $0.1 million paid to the Partnership's preferred unitholders and general partner, respectively.

The Partnership paid the following distributions on the common units during the years ended December 31, 2015, 2016 and 2017 (in thousands):

Year Paid	Periods Covered	Total	Paid to Common Unitholders	Paid to General Partner	Paid to Phantom and Restricted Unitholders Under the LTIP
2015		$19,651	$ 18,567	$ 707	$ 376

	Quarters ending December 31, 2014, March 31, 2015, June 30, 2015 and September 30, 2015				
2016	Quarters ending December 31, 2015, March 31, 2016, June 30, 2016 and September 30, 2016	$21,900	$ 20,509	$ 933	$ 458
2017	Quarters ending December 31, 2016, March 31, 2017, June 30, 2017 and September 30, 2017	$23,629	$ 22,147	$ 994	$ 488

In addition, on January 23, 2018, the Board approved a cash distribution of $0.1450 per outstanding common unit for the quarter ending December 31, 2017. The distribution was paid on February 14, 2018, to unitholders of record as of February 2, 2018. The total distribution was approximately $6.2 million, with approximately $5.8 million and $0.3 million paid to the Partnership's common unitholders and general partner, respectively, and $0.1 million paid to holders of phantom and restricted units pursuant to awards granted under the LTIP.

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12. MAJOR CUSTOMERS AND CONCENTRATION OF CREDIT RISK

Significant customers are defined as those who represent 10% or more of our total consolidated revenues during the year.

For the year ended December 31, 2015, Vitol accounted for approximately 21% of the Partnership's total revenues across all of the Partnership's operating segments.

For the year ended December 31, 2016, Ergon accounted for approximately 13% of the Partnership's total revenues, all of which were earned in asphalt terminalling services. Vitol also accounted for approximately 13% of the Partnership's total revenues, which were earned in all of the Partnership's operating segments.

For the year ended December 31, 2017, Ergon accounted for approximately 31% of the Partnership's total revenues, all of which were earned in asphalt terminalling services. Vitol accounted for approximately 12% of the Partnership's total revenues, which were earned in all of the Partnership's operating segments.

13. RELATED-PARTY TRANSACTIONS

On October 5, 2016, Ergon purchased 100% of the Partnership's general partner from Vitol and Charlesbank, resulting in Ergon being classified as a related party and Vitol and Charlesbank no longer being classified as related parties as of October 5, 2016.

The Partnership leases facilities to Ergon and provides liquid asphalt terminalling services to Ergon. For the year ended December 31, 2015, the Partnership recognized revenues of $15.5 million for services provided to Ergon, all of which is classified as third-party revenues. For the year ended December 31, 2016, the Partnership recognized revenues of $22.2 million for services provided to Ergon, of which $11.0 million is classified as related-party revenue. For the year ended December 31, 2017, the Partnership recognized revenues of $56.4 million for services provided to Ergon, all of which is classified as related-party revenue. As of December 31, 2016 and 2017, the Partnership had receivables from Ergon of $1.7 million and $3.1 million, respectively.

A subsidiary of Ergon provides natural gas service to one of the Partnership's asphalt terminalling facilities. For the year ended December 31, 2017, the Partnership recognized $0.5 million of expense for services provided by this subsidiary.

The Partnership also provided operating and administrative services to Advantage Pipeline. On April 3, 2017, the Partnership sold its investment in Advantage Pipeline and the operating and administrative services agreement was terminated. For the years ended December 31, 2015, 2016 and 2017, the Partnership recognized revenues of $1.3 million, $1.3 million and $0.3 million, respectively, for services provided to Advantage Pipeline. As of December 31, 2016, the Partnership had receivables from Advantage Pipeline of $0.1 million.

The Partnership provides crude oil gathering, transportation and terminalling services to Vitol. For the years ended December 31, 2015 and 2016, the Partnership recognized related-party revenues of $37.8 million and $17.9 million, respectively, for services provided to Vitol. As of December 31, 2016, the Partnership had receivables, net of allowances for doubtful accounts, from Vitol of $1.0 million.

Ergon 2017 Lubbock and Saginaw Storage and Handling Agreement

In September 2016, the Partnership and Ergon entered into a storage, throughput and handling agreement pursuant to which the Partnership provides Ergon storage and terminalling services at the Lubbock and Saginaw asphalt terminal facilities. The term of this agreement commenced on January 1, 2017, and continues for six years. 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. During the year ended December 31, 2017, the Partnership generated revenues under this agreement of $12.9 million.

Ergon 2016 Storage and Handling Agreement

In October 2016, the Partnership and Ergon entered into a storage, throughput and handling agreement (the "Ergon 2016 Storage and Handling Agreement") pursuant to which the Partnership provides Ergon storage and terminalling services at nine asphalt terminal facilities. The term of the Ergon 2016 Storage, Throughput and Handling Agreement commenced on October 5, 2016, and continues for seven years. 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. During the years ended December 31, 2016 and 2017, the Partnership generated revenue under this agreement of $6.2 million and $26.4 million, respectively, all of which is classified as related-party revenue.

Ergon Fontana and Las Vegas Storage Throughput and Handling Agreement

In October 2016, the Partnership and Ergon entered into a storage, throughput and handling agreement (the "Ergon Fontana and Las Vegas Storage Throughput and Handling Agreement") pursuant to which the Partnership provides Ergon storage and terminalling services at two asphalt facilities. The term of the Ergon Fontana and Las Vegas Storage Throughput and Handling Agreement commenced on October 5, 2016, and is scheduled to expire on December 31, 2018. The original Ergon Fontana and Las Vegas Master Facilities Lease Agreement commenced on May 18, 2009, and was a part of Ergon Master Facilities Lease and Sublease Agreement. See Ergon Master Facilities Lease and Sublease Agreement for additional detail regarding prior terms and conditions. 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. During the years ended December 31, 2016 and 2017, the Partnership generated revenues under this agreement of $1.5 million and $6.2 million, respectively, all of which is classified as related-party revenue.

Ergon Master Facilities Lease and Sublease Agreement

In May 2009, the Partnership and Ergon entered into a facilities lease and sublease agreement (the "Ergon Master Facilities Lease and Sublease Agreement") pursuant to which the Partnership leases Ergon certain facilities. The original term of the Ergon Master Facilities Lease and Sublease Agreement commenced on May 18, 2009, for two years, until December 31, 2011. The Ergon Master Facilities Lease and Sublease Agreement has been amended and extended several times and currently encompasses eight facilities and is scheduled to expire on December 31, 2018. The Board's conflicts committee reviewed and approved these agreements in accordance with the Partnership's procedures for approval of related-party transactions and the provisions of the partnership agreement. During the year ended December 31, 2015, the Partnership generated revenues under this agreement of $10.5 million, all of which is classified as third-party revenue. During the year ended December 31, 2016, the Partnership generated revenues under this agreement of $9.2 million, of which $1.8 million is classified as related-party revenue. During the year ended December 31, 2017, the Partnership generated revenues under this agreement of $5.2 million, all of which is classified as related-party revenue.

Ergon Master Facilities Sublease and Sublicense Agreement

In May 2009, the Partnership and Ergon entered into multiple sublease and sublicense agreements covering five facilities. The original terms of these agreements commenced on May 18, 2009, for two years, until December 31, 2011. In November 2010, these multiple leases were consolidated under one master sublease and sublicense agreement. This agreement was amended in June 2015 and has a term scheduled to expire on December 31, 2018. During the year ended December 31, 2015, the Partnership generated revenues under this agreement of $3.2 million, all of which is classified as third-party revenue. During the year ended December 31, 2016, the Partnership generated revenues under this agreement of $3.6 million, of which $1.0 million is classified as related-party revenue. During the year ended December 31, 2017, the Partnership generated revenues under this agreement of $3.7 million, all of which is classified as related-party revenue.

Vitol Storage Agreements

In recent years, a significant portion of the Partnership's crude oil storage capacity has been dedicated to Vitol under multiple agreements. As of December 31, 2015, 2016 and 2017, 2.2 million barrels of storage capacity were dedicated to Vitol under these storage agreements. Service revenues under these agreements are based on the barrels of storage capacity dedicated to Vitol under the applicable agreement at rates that, the Partnership believes, 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 these agreements in accordance with the Partnership's procedures for approval of related-party transactions and the provisions of the partnership agreement. For the year ended December 31, 2015, the Partnership generated revenues under these agreements of approximately $9.4 million, all of which is classified as related-party revenue. For the year ended December 31, 2016, the Partnership generated revenues under these agreements of approximately $9.6 million, of which $7.5 million is classified as related-party revenue. All revenue under these agreements for 2017 is classified as third-party revenue.

As of March 1, 2018, 2.2 million barrels of storage capacity were dedicated to Vitol under the crude oil storage agreement with the current term scheduled to expire on April 30, 2018.

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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") and Vitol's crude oil gathering system located near Midland, Texas (the "Midland Gathering System"). Pursuant to the Vitol O&M Agreement, the Partnership provided certain operating and maintenance services with respect to the Midland Terminal and Midland Gathering System. The term of the Vitol O&M Agreement commenced on September 1, 2012, and was terminated in July 2015. During the year ended December 31, 2015, the Partnership generated revenues of $2.5 million under the Vitol O&M Agreement, which included a termination fee of $1.2 million and transition services fees of $0.1 million. The Partnership believes that the rates it charged Vitol under the Vitol O&M Agreement were fair and reasonable to the Partnership and its unitholders and were comparable with the rates the Partnership charges third parties. The Board's conflicts committee reviewed and approved the Vitol O&M Agreement in accordance with the Partnership's procedures for approval of related-party transactions and the provisions of the partnership agreement.

14. LONG-TERM INCENTIVE PLAN

In July 2007, the general partner adopted the LTIP, which is administered by the compensation committee of the Board. Effective April 29, 2014, the Partnership's unitholders approved an amendment to the LTIP to increase the number of common units reserved for issuance under the incentive plan to 4.1 million common units, subject to adjustment for certain events. 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 and phantom units are entitled to receive cash distributions paid on common units during the vesting period which are reflected initially as a reduction of partners' capital. Distributions paid on units that 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 connection with each anniversary of joining the Board, restricted common units are granted to the independent directors. The units vest in one-third increments over three years. The following table includes information on grants made to the directors under the LTIP subject to vesting requirements:

Grant Date	Number of Units	Weighted Average Grant Date Fair Value	Grant Date Total Fair Value (in thousands)
December 2015	15,120	$ 5.06	$ 77
December 2016	10,950	$ 6.85	$ 75
December 2017	15,306	$ 4.85	$ 74

In October 2016, all of the independent directors' remaining unvested 2015 units vested due to the Ergon Change of Control. The Partnership recorded compensation cost of $0.1 million during the year ended December 31, 2016, related to this early vesting.

In addition, the independent directors received common unit grants that have no vesting requirement as part of their compensation. The following table includes information on grants made to the directors under the LTIP that have no vesting requirement:

Grant Date	Number of Units	Weighted Average Grant Date Fair Value	Grant Date Total Fair Value (in thousands)
December 2016	10,220	$ 6.85	$ 70
December 2017	14,286	$ 4.85	$ 69

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The Partnership also grants phantom units to employees. 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 following table includes information on the outstanding grants:

Grant Date	Number of Units	Weighted Average Grant Date Fair Value	Grant Date Total Fair Value (in thousands)
March 2015	266,076	$ 7.74	$ 2,059
March 2016	416,131	$ 4.77	$ 1,985
October 2016	9,960	$ 5.85	$ 58
March 2017	323,339	$ 7.15	$ 2,312

The unrecognized estimated compensation cost relating to outstanding phantom units at December 31, 2017, was $2.1 million, which will be recognized over the remaining vesting period. On January 1, 2018, 206,238 units of the March 2015 grant vested.

In September 2012, Mark Hurley was granted 500,000 phantom units under the LTIP upon his employment as the Chief Executive Officer of the general partner. These grants were equity awards under ASC 718 – Stock Compensation and, accordingly, the fair value of the awards as of the grant date was expensed over the vesting period. These units vested ratably over five years pursuant to the Employee Phantom Unit Agreement between Mr. Hurley and the general partner and did not include DERs. The weighted average grant date fair value per unit 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. The final portion of this award vested during September 2017, and there was no unrecognized estimated compensation cost as of December 31, 2017.

The Partnership's equity-based incentive compensation expense for the years ended December 31, 2015, 2016 and 2017 was $2.7 million, $2.5 million and $2.2 million, respectively.

Activity pertaining to phantom common units and restricted common unit awards granted under the LTIP is as follows:

	Number of Units	Weighted Average Grant Date Fair Value
Nonvested, December 31, 2016	915,180	$ 6.61
Granted	352,931	6.96
Vested	331,860	7.82
Forfeited	12,700	6.69
Nonvested, December 31, 2017	923,551	$ 6.29

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 $1.5 million for the year ended December 31, 2015, and $1.2 million for each of the years ended December 31, 2016 and 2017, 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 the Board for approval. The Partnership recognized expense of $0.9 million for the year ended December 31, 2015, and $0.8 million for each of the years ended December 31, 2016 and 2017, respectively, for discretionary profit sharing contributions under the 401(k) Plan.

16. 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"). Upon the Ergon Change of Control, Vitol and Charlesbank, the previous owners of HoldCo, repurchased and canceled the Profits Interest.

Although the entire economic burden of the Profits Interest, which was equity classified, was borne solely by HoldCo and did not impact the Partnership's cash or units outstanding, the intent of the Profits Interest was to provide a performance incentive and encourage retention of Mr. Hurley. Therefore, the Partnership recognized the grant date fair value of the Profits Interest as compensation expense over the service period and the repurchase of the Profits Interest in the period paid. The expense is also reflected as a capital contribution and, therefore, results in a corresponding credit to partners' capital in the Partnership's consolidated financial statements. The Partnership recognized expense of $0.1 million and $0.9 million in relation to the Profits Interest during the years ended December 31, 2015 and 2016, respectively.

17. COMMITMENTS AND CONTINGENCIES

The Partnership leases certain real property, equipment and operating facilities under various operating 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 no longer be required for operations. Future non-cancellable commitments related to these items at December 31, 2017, are summarized below (in thousands):

For year ending:	Operating Leases
December 31, 2018	$ 4,813
December 31, 2019	3,307
December 31, 2020	1,707
December 31, 2021	1,022
December 31, 2022	736
Thereafter	1,284
Total future minimum lease payments	$ 12,869

Rental expense related to operating leases was $9.5 million, $6.5 million and $6.2 million for the years ended December 31, 2015, 2016 and 2017, respectively.

The Partnership is from time to time subject to various legal actions and claims incidental to its business. 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.

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 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 services will cease, and the Partnership does not believe that such demand will cease in 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.

18. 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

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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, 2016 and 2017, the Partnership was aware of existing conditions that may cause it to incur expenditures in the future for the remediation of existing environmental matters. The Partnership had no related loss contingencies as of December 31, 2016. The Partnership had loss contingencies of $0.1 million related to environmental matters as of December 31, 2017. Changes in the Partnership's estimates and assumptions may occur as a result of the passage of time and the occurrence of future events.

19. FAIR VALUE MEASUREMENTS

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, to minimize the use of unobservable inputs when determining fair value. In periods in which they occur, the Partnership recognizes transfers into and out of Level 3 as of the end of the reporting period. Transfers out of Level 3 represent existing assets and liabilities that were classified previously as Level 3 for which the observable inputs became a more significant portion of the fair value estimates. Determining the appropriate classification of the Partnership's fair value measurements within the fair value hierarchy requires management's judgment regarding the degree to which market data is observable or corroborated by observable market data.

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, 2016			
Description	Total	Quoted Prices in Active Markets for Identical Assets	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)

		(Level 1)		
Liabilities:				
Interest rate swap liabilities	$1,947	$ —	$ 1,947	$ —
Total swap liabilities	$1,947	$ —	$ 1,947	$ —

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	Fair Value Measurements as of December 31, 2017			
Description	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Assets:				
Interest rate swap assets	$68	$ —	$ 68	$ —
Total swap assets	$68	$ —	$ 68	$ —
Liabilities:				
Interest rate swap liabilities	$225	$ —	$ 225	$ —
Total swap liabilities	$225	$ —	$ 225	$ —

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, 2017, the carrying values on the 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, 2017, 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.

20. OPERATING SEGMENTS

The Partnership's operations consist of four operating segments: (i) asphalt terminalling services, (ii) crude oil terminalling services, (iii) crude oil pipeline services and (iv) crude oil trucking and producer field services.

ASPHALT TERMINALLING SERVICES — The Partnership provides liquid asphalt cement and residual fuel oil terminalling services at its 56 terminalling facilities located in 26 states.

CRUDE OIL TERMINALLING SERVICES — The Partnership provides crude oil terminalling services at its terminalling facility located in Oklahoma.

CRUDE OIL PIPELINE SERVICES — The Partnership owns and operates pipeline systems 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 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 pipeline system. The Partnership previously owned and operated the East Texas pipeline system, which is located in Texas. On April 18, 2017, the Partnership sold the East Texas pipeline system. See Note 7 for additional information. Crude oil marketing revenues consist of sales proceeds recognized for the sale of crude oil to third-party customers. Revenue for the sale of crude oil is recognized when title to the crude oil transfers to the customer and is based on contractual prices for the sale of crude oil.

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 terminalling 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.

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The Partnership's management evaluates performance based upon segment operating margin, which includes revenues from related parties and external customers and operating expense 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. The Partnership accounts for intersegment product sales as if the sales were to third parties, that is, at current market prices. 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):

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	Year ended December 31,		
	2015	2016	2017
Asphalt Terminalling Services			
Service revenue:			
Third-party revenue	$72,152	$75,655	$57,486
Related-party revenue	1,278	11,762	56,378
Total revenue for reportable segments	73,430	87,417	113,864
Operating expense (excluding depreciation and amortization)	25,218	30,648	49,241
Operating margin (excluding depreciation and amortization)	48,212	56,769	64,623
Additions to long-lived assets	19,769	148,622	22,046
Total assets (end of period)	$98,848	$141,280	$146,966
Crude Oil Terminalling Services			
Service revenue:			
Third-party revenue	$13,076	$16,387	$22,177
Related-party revenue	11,522	7,858	—
Total revenue for reportable segments	24,598	24,245	22,177
Operating expense (excluding depreciation and amortization)	5,756	4,197	4,200
Operating margin (excluding depreciation and amortization)	18,842	20,048	17,977
Additions to long-lived assets	3,282	2,126	2,194
Total assets (end of period)	$73,502	$71,689	$69,149
Crude Oil Pipeline Services			
Service revenue:			
Third-party revenue	$15,148	$8,662	$9,580
Related-party revenue	10,687	5,433	310
Product sales revenue:			
Third-party revenue	3,511	20,968	11,094
Total revenue for reportable segments	29,346	35,063	20,984
Operating expense (excluding depreciation and amortization)	18,162	15,270	13,310
Operating expense (intersegment)	259	890	417
Cost of product sales	3,231	14,130	8,807
Cost of product sales (intersegment)	—	426	150
Operating margin (excluding depreciation and amortization)	7,694	4,347	(1,700)
Additions to long-lived assets	34,953	8,250	2,934
Total assets (end of period)	$175,142	$150,043	$117,749
Crude Oil Trucking and Producer Field Services			
Service revenue:			
Third-party revenue	$37,039	$25,511	$24,529
Related-party revenue	15,616	5,158	—
Intersegment revenue	259	890	417
Product sales revenue:			
Third-party revenue	—	—	385
Intersegment revenue	—	426	150

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	Year ended December 31,		
	2015	2016	2017
Total revenue for reportable segments	52,914	31,985	25,481
Operating expense (excluding depreciation and amortization)	51,610	30,156	25,915
Operating margin (excluding depreciation and amortization)	1,304	1,829	(434)
Additions to long-lived assets	4,556	2,558	1,701
Total assets (end of period)	$17,256	$12,651	$7,005
Total operating margin (excluding depreciation and amortization)(1)	$76,052	$82,993	$80,466
Total segment revenues	180,288	178,710	182,506
Elimination of intersegment revenues	(259)	(1,316)	(567)
Consolidated revenues	180,029	177,394	181,939

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(1) The following table reconciles segment operating margin (excluding depreciation and amortization) to income (loss) before income taxes (in thousands):

	Year ended December 31,		
	2015	2016	2017
Operating margin (excluding depreciation and amortization)	$76,052	$82,993	$80,466
Depreciation and amortization	(27,228)	(30,820)	(31,139)
General and administrative expenses	(18,976)	(20,029)	(17,112)
Asset impairment expense	(21,996)	(25,761)	(2,400)
Gain (loss) on sale of assets	6,137	108	(975)
Equity earnings in unconsolidated affiliate	3,932	1,483	61
Gain on sale of unconsolidated affiliate	—	—	5,337
Interest expense	(11,202)	(12,554)	(14,027)
Income (loss) before income taxes	$6,719	$(4,580)	$20,211

21. 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 applicable corporate tax rate 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 applicable corporate tax rate and will likely pay state (and possibly local) income tax at varying rates. Distributions from this subsidiary will generally

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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.

On December 22, 2017, the Tax Cut and Jobs Act ("TCJA") was enacted into law. Among its many tax reform provisions, TCJA reduced the federal corporate income tax rate from 35% to 21% for the tax year beginning after December 31, 2017. As a result, the Partnership revalued the deferred tax effects of the temporary differences between its taxable subsidiary's tax basis of assets and liabilities and the financial reporting amounts at December 31, 2017, which resulted in a reduction of the taxable subsidiary's gross deferred tax asset of $0.3 million. The net deferred tax effect of the taxable entity's temporary differences at December 31, 2017, are presented below (in thousands):

Deferred Tax Asset	
Difference in bases of property, plant and equipment	$484
Deferred tax asset	484
Less: valuation allowance	(484)
Net deferred tax asset	$—

The Partnership has considered the taxable income projections in future years, whether the carryforward period is so brief that it would limit realization of tax benefits, whether future revenue and operating cost projections will produce enough taxable income to realize the deferred tax asset based on existing service rates and cost structures, and the Partnership's earnings history exclusive of the loss that created the future deductible amount for the Partnership's subsidiary that is taxed as a corporation for purposes of determining the likelihood of realizing the benefits of the deferred tax assets. As a result of the Partnership's consideration of these factors, the Partnership has provided a full valuation allowance against its deferred tax asset as of December 31, 2017.

22. RECENTLY ISSUED ACCOUNTING STANDARDS

In May 2014, the FASB issued ASU 2014-09, "Revenue from Contracts with Customers." The amendments in this update create Topic 606, Revenue from Contracts with Customers, and supersede the revenue recognition requirements in Topic 605, Revenue Recognition, including most industry-specific revenue recognition guidance throughout the Industry Topics of the Codification. In summary, the core principle of Topic 606 is that an entity recognizes revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. Throughout 2015, 2016 and 2017, the FASB issued a series of subsequent updates to the revenue recognition guidance in Topic 606.

The amendments in ASU 2014-09 and the related updates are effective for public entities for annual reporting periods beginning after December 15, 2017, and for interim periods within that reporting period. The Partnership adopted this standard as of January 1, 2018, using the modified retrospective approach, which allows for applying the new standard to (i) all new contracts entered into after January 1, 2018, and (ii) all existing contracts for which all (or substantially all) of the revenue has not been recognized under legacy revenue guidance as of January 1, 2018, through a cumulative adjustment to equity. Revenues presented in the comparative consolidated financial statements for periods prior to January 1, 2018, will not be revised.

The impact of adopting the new standard on the Partnership's financial statements is not material, and the Partnership will have no cumulative adjustment to Partners' capital as of January 1, 2018, related to the adoption of the standard. The impact of adopting Topic 606 primarily relates to the timing of the Partnership's revenue recognition on some of its minimum throughput fees, which could be deferred within a single reporting year. As a result, some revenue that was historically recognized in the third quarter will now be recognized in the fourth quarter of each year. The overall impact to the Partnership's results is not material as the analysis of the Partnership's contracts under the new revenue recognition standard supports the recognition of revenue as services are performed, which is consistent with the Partnership's current revenue recognition model. Revenue from the majority of the Partnership's contracts will continue to be recognized as services are performed. Topic 606 requires the separate presentation of revenue from customers accounted for under Topic 606 and revenue from leases accounted for under Topic 840 on the face of the statement of operations and, as a result, the Partnership will begin separately presenting these two components of revenue in its consolidated financial statements to be included in the Partnership's Form 10-Q for the three-month period ending March 31, 2018. In addition, the adoption of the new guidance will require expanded disclosures.

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In November 2015, the FASB issued ASU 2015-17, "Income Taxes (Topic 740)." This update simplifies the presentation of deferred income taxes on the balance sheet. This update is effective for financial statements issued for annual periods beginning after December 15, 2016, and interim periods within those fiscal years. The Partnership adopted this update in the three-month period ended March 31, 2017, and there was no impact on the Partnership's financial position, results of operations or cash flows.

In January 2016, the FASB issued ASU 2016-01, "Financial Instruments - Overall (Subtopic 825-10)." This update is intended to enhance the reporting model for financial instruments in order to provide users of financial statements with more decision-useful information. The amendments in the update address certain aspects of recognition, measurement, presentation and disclosure of financial instruments. This update is effective for financial statements issued for annual periods beginning after December 15, 2017, and interim periods within those fiscal years. The Partnership has evaluated the impact of this guidance, which will be adopted beginning with the Partnership's quarterly report for the three-month period ending March 31, 2018, and there will be no impact on the Partnership's financial position, results of operations or cash flows.

In February 2016, the FASB issued ASU 2016-02, "Leases (Topic 842)." This update introduces a new lease model that requires the recognition of lease assets and lease liabilities on the balance sheet and the disclosure of key information about leasing arrangements. Throughout 2017 and 2018, the FASB issued a series of subsequent updates to the guidance in Topic 842. This update, as well as related updates, is effective for financial statements issued for annual periods beginning after December 15, 2018, and interim periods within those fiscal years. The Partnership is evaluating the impact of this guidance, which will be adopted beginning with the Partnership's quarterly report for the three-month period ending March 31, 2019.

In March 2016, the FASB issued ASU 2016-09, "Compensation - Stock Compensation (Topic 718)." This update is intended to simplify the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities and classification on the statement of cash flows. This update is effective for financial statements issued for annual periods beginning after December 15, 2016, and interim periods within those fiscal years. The Partnership adopted this update in the three-month period ended March 31, 2017, and there was no impact on the Partnership's financial position, results of operations or cash flows.

In August 2016, the FASB issued ASU 2016-15, "Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments." This update addresses the following eight specific cash flow issues: debt prepayment or debt extinguishment costs; settlement of zero-coupon debt instruments or other debt instruments with coupon interest rates that are insignificant in relation to the effective interest rate of the borrowing; contingent consideration payments made after a business combination; proceeds from the settlement of insurance claims; proceeds from the settlement of corporate-owned life insurance policies (including bank-owned life insurance policies); distributions received from equity method investees; beneficial interests in securitization transactions; and separately identifiable cash flows and application of the predominance principle. This update is effective for financial statements issued for annual periods beginning after December 15, 2017, and interim periods within those fiscal years. The Partnership has evaluated the impact of this guidance, which will be adopted beginning with the Partnership's quarterly report for the three-month period ending March 31, 2018, and there will be no impact on the Partnership's financial position, results of operations or cash flows.

In October 2016, the FASB issued ASU 2016-16, "Income Taxes (Topic 740): Intra-Entity Transfers of Assets Other than Inventory." This update is intended to improve the accounting for the income tax consequences of intra-entity transfers of assets other than inventory. The amendments in the update eliminate the prohibition of recognizing current and deferred income taxes for an intra-entity asset transfer other than inventory until the asset has been sold to an outside party. This update is effective for financial statements issued for annual periods beginning after December 15, 2017, and interim periods within those fiscal years. The Partnership has evaluated the impact of this guidance, which will be adopted beginning with the Partnership’s quarterly report for the three-month period ending March 31, 2018, and there will be no impact on the Partnership’s financial position, results of operations or cash flows.

In November 2016, the FASB issued ASU 2016-18, “Statement of Cash Flows (Topic 230): Restricted Cash (a Consensus of the FASB Emerging Issues Task Force).” This update requires that a statement of cash flows explain the change during the period in the total of cash, cash equivalents and amounts generally described as restricted cash or restricted cash equivalents. This update is effective for financial statements issued for annual periods beginning after December 15, 2017, and interim periods within those fiscal years. The Partnership has evaluated the impact of this guidance, which will be adopted beginning with the Partnership’s quarterly report for the three-month period ending March 31, 2018, and there will be no impact on the Partnership’s financial position, results of operations or cash flows.

In January 2017, the FASB issued ASU 2017-01, “Business Combinations (Topic 805): Clarifying the Definition of a Business.” This update clarifies the definition of a business with the objective of adding guidance to assist entities with

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evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. This update is effective for financial statements issued for annual periods beginning after December 15, 2017, and interim periods within those fiscal years. The Partnership has evaluated the impact of this guidance, which will be adopted beginning with the Partnership's quarterly report for the three-month period ending March 31, 2018.

In January 2017, the FASB issued ASU 2017-04, "Intangibles - Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment." This update simplifies how an entity is required to test goodwill for impairment by eliminating Step 2 from the goodwill impairment test. Step 2 measures a goodwill impairment loss by comparing the implied fair value of a reporting unit's goodwill with the carrying amount of that goodwill. This update is effective for financial statements issued for annual periods beginning after December 15, 2019, and interim periods within those fiscal years. The Partnership early-adopted this update in the fourth quarter of 2017 and there was no impact on the Partnership's financial position, results of operations or cash flows.

In February 2017, the FASB issued ASU 2017-05, "Other Income - Gains and Losses from the Derecognition of Nonfinancial Assets (Subtopic 610-20)." This update clarifies the scope of Subtopic 610-20 and adds guidance for partial sales of nonfinancial assets. Subtopic 610-20, which was issued in May 2014 as a part of ASU 2014-09, "Revenue from Contracts with Customers (Topic 606)", provides guidance for recognizing gains and losses from the transfer of nonfinancial assets in contracts with noncustomers. The amendments in ASU 2017-05 are effective for public entities for annual reporting periods beginning after December 15, 2017, and for interim periods within that reporting period. Early adoption is permitted for annual reporting periods beginning after December 15, 2016. The Partnership has evaluated the impact of this standard, which will be adopted beginning with the Partnership's quarterly report for the three-month period ending March 31, 2018, and does not expect a material impact on the Partnership's financial position, results of operations or cash flows.

In May 2017, the FASB issued ASU 2017-09, "Compensation - Stock Compensation (Topic 718): Scope of Modification Accounting." This update provides clarity and reduces both diversity in practice and cost and complexity when applying the guidance of Topic 718, Compensation - Stock Compensation, to a change in the terms or conditions of a share-based payment award. This update is effective for financial statements issued for annual periods beginning after December 15, 2017, and interim periods within those fiscal years. The Partnership has evaluated the impact of this guidance, which will be adopted beginning with the Partnership's quarterly report for the three-month period ending March 31, 2018, and does not expect a material impact on the Partnership's financial position, results of operations or cash flows.

23. 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	Full Year
2016:					
Revenues	$41,009	$43,425	$46,939	$46,021	$177,394
Operating income (loss)[(1)]	5,013	(15,348)	13,398	3,428	6,491
Net income (loss)[(1)]	726	(18,936)	11,419	1,951	(4,840)
Basic and diluted net income (loss) per common unit	(0.14)	(0.71)	0.13	(0.18)	(0.87)
2017:					
Revenues[(2)]	$46,340	$43,877	$47,474	$44,248	$181,939
Operating income[(2)]	6,557	6,505	12,219	3,559	28,840
Net income[(2)]	3,542	6,371	9,771	361	20,045
Basic and diluted net income (loss) per common unit	(0.08)	—	0.08	(0.15)	(0.15)

(1) Operating loss and net loss for the second quarter of 2016 are impacted by asset impairments as described in Note 3.

(2) In April 2017, the Partnership sold the East Texas pipeline system and its investment in Advantage Pipeline. See "Item 7-Management's Discussion and Analysis" for discussion on the impact these changes had on the Partnership's consolidated financial statements.

24. SUBSEQUENT EVENTS

On March 7, 2018, the Partnership acquired an asphalt terminalling facility located in Oklahoma from a third party for $22.0 million.