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<br>(State or other jurisdiction of incorporation or organization) | 20-8536826<br>(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 state 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 | Blueknight Energy Partners, L.P. | |
| BP p.l.c. Centurion Pipeline, | ConocoPhillips Deeprock Energy | Blueknight Energy Partners, L.P. |
| L.P. Enbridge Inc. | Resources LLC Enbridge Energy | BP p.l.c. |
| Enterprise Products Partners | Partners, L.P. | Centurion Pipeline, L.P. ConocoPhillips Diamond |
| L.P. Magellan Midstream | Enterprise Products Partners L.P. | Pipeline, LLC Marathon Pipe Line, LLC |
| Partners, L.P. NGL Energy | Kinder Morgan, Inc. | Magellan Midstream Partners, L.P. |
| Partners, L.P. | Magellan Midstream Partners, L.P. | NGL Energy Partners, L.P. |
| Plains All American | NGL Energy Partners, L.P. | Osage Pipeline Company, LLC |
| Pipeline, L.P. | Plains All American Pipeline, L.P. | Plains All American Pipeline, L.P. |
| SemGroup Corporation | SemGroup Corporation | SemGroup Corporation |
| Sunoco Logistics Partners, | Sunoco Logistics Partners, L.P. | Seaway Crude Pipeline Company LLC |
| L.P. Tallgrass Pony Express | TransCanada Corp. | Sunoco Logistics Partners, L.P. |
| Pipeline, LLC | | TransCanada Corp. |
| TransCanada Corp. | | |
| White Cliffs Pipeline, LLC | | |

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

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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

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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.

(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 | $ | | | |