Blueknight Energy Partners, L.P.
Form 10-Q
November 01, 2017

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

FORM 10-Q

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

For the quarterly period ended September 30, 2017

OR

o TRANSITION REPORT PURSUANT TO SECTION 13 or 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from __________ to _________

Commission File Number 001-33503

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

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

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

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

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

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 x 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 x No 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 x

As of October 27, 2017, there were 35,125,202 Series A Preferred Units and 38,242,025 common units outstanding.

Table of Contents

PART I. FINANCIAL INFORMATION

Item 1. Unaudited Condensed Consolidated Financial Statements

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

	As of December 31, 2016	As of September 30, 2017 (unaudited)
ASSETS		
Current assets:		
Cash and cash equivalents	$3,304	$ 2,648
Accounts receivable, net of allowance for doubtful accounts of $49 and $30 at December 31, 2016 and September 30, 2017, respectively	7,544	7,915
Receivables from related parties, net of allowance for doubtful accounts of $0 at both dates	1,860	1,970
Prepaid insurance	1,578	2,552
Other current assets	7,934	7,496
Total current assets	22,220	22,581
Property, plant and equipment, net of accumulated depreciation of $292,117 and $307,669 at December 31, 2016 and September 30, 2017, respectively	307,334	292,574
Assets held for sale, net of accumulated depreciation of $3,041 at December 31, 2016	4,237	—
Investment in unconsolidated affiliate	20,561	—
Goodwill	4,746	4,746
Debt issuance costs, net	2,050	4,662
Intangibles and other assets, net	14,515	13,494
Total assets	$375,663	$ 338,057
LIABILITIES AND PARTNERS’ CAPITAL		
Current liabilities:		
Accounts payable	$3,174	$ 3,582
Accounts payable to related parties	1,053	1,379
Accrued interest payable	413	751
Accrued property taxes payable	2,531	3,691
Unearned revenue	2,350	2,303
Unearned revenue with related parties	383	4,407
Accrued payroll	6,358	5,554
Current interest rate swaps liabilities	—	61
Other current liabilities	4,279	4,311
Total current liabilities	20,541	26,039
Long-term unearned revenue with related parties	640	451
Other long-term liabilities	2,959	3,678
Long-term interest rate swaps liabilities	1,947	633
Long-term debt	324,000	297,592
Commitments and contingencies (Note 14)		
Partners’ capital:		
Common unitholders (38,003,397 and 38,242,025 units issued and outstanding at December 31, 2016 and September 30, 2017, respectively)	471,180	455,423
Series A Preferred Units (35,125,202 units issued and outstanding at both dates)	253,923	253,923

General partner interest (1.7% and 1.6% interest at December 31, 2016 and September 30, 2017, respectively, with 1,225,409 general partner units outstanding at both dates)	(699,527)	(699,682)
Total partners' capital	25,576	9,664
Total liabilities and partners' capital	$375,663	$ 338,057

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

1

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

	Three Months ended September 30,		Nine Months ended September 30,	
	2016	2017	2016	2017
	(unaudited)			
Service revenue:				
Third party revenue	$35,600	$30,635	$96,711	$87,443
Related party revenue	5,734	14,464	18,605	41,611
Product sales revenue:				
Third party revenue	5,605	2,375	16,058	8,637
Total revenue	46,939	47,474	131,374	137,691
Costs and expenses:				
Operating	25,267	29,380	80,314	91,896
Cost of product sales	3,513	1,675	10,789	6,483
General and administrative	4,865	4,093	14,447	13,000
Asset impairment expense	—	—	22,845	45
Total costs and expenses	33,645	35,148	128,395	111,424
Gain (loss) on sale of assets	104	(107)	85	(986)
Operating income	13,398	12,219	3,064	25,281
Other income (expense):				
Equity earnings in unconsolidated affiliate	305	—	1,086	61
Gain on sale of unconsolidated affiliate	—	1,112	—	5,284
Interest expense (net of capitalized interest of $0, $1, $41 and $6, respectively	(2,175)	(3,500)	(10,742)	(10,795)
Income (loss) before income taxes	11,528	9,831	(6,592)	19,831
Provision for income taxes	109	60	199	147
Net income (loss)	$11,419	$9,771	$(6,791)	$19,684
Allocation of net income (loss) for calculation of earnings per unit:				
General partner interest in net income	$341	$312	$291	$777
Preferred interest in net income	$6,279	$6,279	$17,058	$18,837
Net income (loss) available to limited partners	$4,799	$3,180	$(24,140)	$70
Basic and diluted net income (loss) per common unit	$0.13	$0.08	$(0.69)	$—
Weighted average common units outstanding - basic and diluted	36,036	38,189	34,139	38,164

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

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

	Common Unitholders	Series A Preferred Unitholders	General Partner Interest	Total Partners' Capital
	(unaudited)			
Balance, December 31, 2016	$471,180	$253,923	$(699,527)	$25,576
Net income	64	18,837	783	19,684
Equity-based incentive compensation	895	—	18	913
Distributions	(16,956)	(18,837)	(1,060)	(36,853)
Capital contributions	—	—	104	104
Proceeds from sale of 53,079 common units pursuant to the Employee Unit Purchase Plan	240	—	—	240
Balance, September 30, 2017	$455,423	$253,923	$(699,682)	$9,664

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

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

	Nine Months ended September 30,	
	2016	2017
	(unaudited)	
Cash flows from operating activities:		
Net income (loss)	$(6,791)	$19,684
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Provision for uncollectible receivables from third parties	(13)	(19)
Provision for uncollectible receivables from related parties	(229)	—
Depreciation and amortization	22,447	23,586
Amortization and write-off of debt issuance costs	767	1,560
Unrealized loss (gain) related to interest rate swaps	886	(1,253)
Asset impairment charge	22,845	45
Loss (gain) on sale of assets	(85)	986
Gain on sale of unconsolidated affiliate	—	(5,284)
Equity-based incentive compensation	1,319	913
Equity earnings in unconsolidated affiliate	(1,086)	(61)
Changes in assets and liabilities		
Decrease (increase) in accounts receivable	139	(352)
Decrease (increase) in receivables from related parties	811	(110)
Decrease in prepaid insurance	2,032	1,964
Decrease in other current assets	329	53
Decrease in other assets	40	56
Decrease in accounts payable	(517)	(142)
Increase in payables to related parties	—	159
Increase in accrued interest payable	28	338
Increase in accrued property taxes	480	1,187
Increase (decrease) in unearned revenue	(9)	775
Increase (decrease) in unearned revenue from related parties	(688)	3,835
Decrease in accrued payroll	(1,682)	(804)
Decrease in other accrued liabilities	(1,110)	(935)
Net cash provided by operating activities	39,913	46,181
Cash flows from investing activities:		
Acquisitions	(18,989)	—
Capital expenditures	(15,643)	(13,312)
Proceeds from sale of assets	1,488	9,202
Proceeds from sale of unconsolidated affiliate	—	26,436
Net cash provided by (used in) investing activities	(33,144)	22,326
Cash flows from financing activities:		
Payment on insurance premium financing agreement	(2,521)	(2,074)
Debt issuance costs	(955)	(4,172)
Borrowings under credit facility	83,000	344,592
Payments under credit facility	(74,000)	(371,000)
Proceeds from equity issuance, net of offering costs	21,315	240
Capital contributions	—	104

Capital contribution related to profits interest	112	—
Distributions	(32,473)	(36,853)
Net cash used in financing activities	(5,522)	(69,163)
Net increase (decrease) in cash and cash equivalents	1,247	(656)
Cash and cash equivalents at beginning of period	3,038	3,304
Cash and cash equivalents at end of period	$4,285	$2,648
Supplemental disclosure of non-cash financing and investing cash flow information:		
Increase (decrease) in accounts payable related to purchases of property, plant and equipment	$(1,279)	$717
Increase in accrued liabilities related to insurance premium financing agreement	$3,189	$2,938

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

4

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

1. ORGANIZATION AND NATURE OF BUSINESS

Blueknight Energy Partners, L.P. (together with its subsidiaries, the “Partnership”) is a publicly traded master limited partnership with operations in 26 states. The Partnership provides integrated terminalling services, which includes storage, handling and blending services, gathering, transportation and marketing services for companies engaged in the production, distribution and marketing of crude oil and asphalt products. The Partnership manages its operations through four operating segments: (i) asphalt terminalling services, (ii) crude oil terminalling services, (iii) crude oil pipeline services and (iv) crude oil trucking and producer field services. The Partnership’s common units and preferred units, which represent limited partnership interests in the Partnership, are listed on the NASDAQ Global Market under the symbols “BKEP” and “BKEPP,” respectively. The Partnership was formed in February 2007 as a Delaware master limited partnership to own, operate and develop a diversified portfolio of complementary midstream energy assets.

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

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

2. BASIS OF CONSOLIDATION AND PRESENTATION

The financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (“GAAP”). The condensed consolidated statements of operations for the three and nine months ended September 30, 2016 and 2017, the condensed consolidated statement of changes in partners’ capital for the nine months ended September 30, 2017, the condensed consolidated statements of cash flows for the nine months ended September 30, 2016 and 2017, and the condensed consolidated balance sheet as of September 30, 2017, are unaudited. In the opinion of management, the unaudited condensed consolidated financial statements have been prepared on the same basis as the audited financial statements and include all adjustments necessary to state fairly the financial position and results of operations for the respective interim periods. All adjustments are of a recurring nature unless otherwise disclosed herein. The 2016 year-end condensed consolidated balance sheet data was derived from audited financial statements but does not include all disclosures required by GAAP. These unaudited condensed consolidated financial statements and notes should be read in conjunction with the consolidated financial statements and notes thereto included in the Partnership’s annual report on Form 10-K for the year ended December 31, 2016, filed with the Securities and Exchange Commission (the “SEC”) on March 9, 2017 (the “2016 Form 10-K”). Interim financial results are not necessarily indicative of the results to be expected for an annual period. The Partnership’s significant accounting policies are consistent with those disclosed in Note 3 of the Notes to Consolidated Financial Statements in its 2016 Form 10-K.

The Partnership’s investment in Advantage Pipeline, L.L.C. (“Advantage Pipeline”), over which the Partnership had significant influence but not control, was accounted for by the equity method. The Partnership did not consolidate any part of the assets or liabilities of its equity investee. The Partnership’s share of net income or loss is reflected as one line item on the Partnership’s unaudited condensed consolidated statements of operations entitled “Equity earnings in unconsolidated affiliate” and increased or decreased, as applicable, the carrying value of the Partnership’s “Investment in unconsolidated affiliate” on the unaudited condensed consolidated balance sheets. Distributions to the Partnership reduced the carrying value of its investment and, to the extent received, would be reflected in the Partnership’s unaudited condensed consolidated statements of cash flows in the line item “Distributions from unconsolidated affiliate.” Contributions increased the carrying value of the Partnership’s investment and were reflected in the Partnership’s unaudited condensed consolidated statements of cash flows in investing activities. On April 3, 2017, the Partnership sold its investment in Advantage Pipeline. See Note 4 for additional information.

3. RESTRUCTURING CHARGES

During the fourth quarter of 2015, the Partnership recognized certain restructuring charges in the crude oil trucking and producer field services segment pursuant to an approved plan to exit the trucking market in West Texas.

Changes in the accrued amounts pertaining to the restructuring charges are summarized as follows (in thousands):

	Three Months ended September 30,		Nine Months ended September 30,	
	2016	2017	2016	2017
Beginning balance	$795	$382	$1,565	$474
Charged to expense	—	—	—	—
Cash payments	192	48	962	140
Ending balance	$603	$334	$603	$334

The remaining accrued amounts relate to lease payments that will be paid over the remaining lease terms, which extend through July 2019.

4. EQUITY METHOD INVESTMENT

The Partnership’s investment in Advantage Pipeline, over which the Partnership had significant influence but not control, was accounted for by the equity method. On April 3, 2017, Advantage Pipeline was acquired by a joint venture formed by affiliates of Plains All American Pipeline, L.P. and Noble Midstream Partners LP. The Partnership received cash proceeds at closing from the sale of its approximate 30% equity ownership interest in Advantage Pipeline of approximately $25.3 million and recorded a gain on the sale of the investment of $4.2 million. Approximately 10% of the gross sale proceeds were held in escrow, subject to certain post-closing settlement terms and conditions. The Partnership received approximately $1.1 million of the funds held in escrow in August 2017. The Partnership expects to receive up to approximately $2.2 million for its pro rata portion of the remaining net escrow proceeds in January 2018. The Partnership’s initial net proceeds received at closing were used to prepay revolving debt (without a commitment reduction). The operating and administrative services agreement to which the Partnership and Advantage Pipeline were parties and under which the Partnership operated the 70-mile, 16-inch Advantage crude oil pipeline, located in the southern Delaware Basin in Texas, was terminated at closing. The Partnership and the Plains/Noble joint venture entered into a short-term transition services agreement under which the Partnership provided certain services through August 1, 2017, when the agreement was terminated.
Summarized financial information for Advantage Pipeline is set forth in the tables below for the periods indicated in which the Partnership held the investment in Advantage Pipeline (in thousands):

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

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

6

	Three Months ended	Nine Months ended	Three Months ended
	September 30, 2016		March 31, 2017
Income statements			
Operating revenues	$3,528	$12,003	$3,150
Operating expenses	$510	$1,586	$465
Net income	$1,176	$4,187	$187

5. PROPERTY, PLANT AND EQUIPMENT

	Estimated Useful Lives (Years)	December 31, 2016	September 30, 2017
		(dollars in thousands)	
Land	N/A	$25,863	$ 24,686
Land improvements	10-20	6,698	6,799
Pipelines and facilities	5-30	165,293	165,224
Storage and terminal facilities	10-35	347,656	356,444
Transportation equipment	3-10	12,391	6,235
Office property and equipment and other	3-20	35,578	34,092
Pipeline linefill and tank bottoms	N/A	3,234	3,233
Construction-in-progress	N/A	2,738	3,530
Property, plant and equipment, gross		599,451	600,243
Accumulated depreciation		(292,117)	(307,669)
Property, plant and equipment, net		$307,334	$ 292,574

Depreciation expense for three months ended September 30, 2016 and 2017 was $7.3 million and $7.4 million, respectively, and depreciation expense for the nine months ended September 30, 2016 and 2017 was $21.6 million and $22.6 million, respectively.

On April 18, 2017, the Partnership sold its East Texas pipeline system. The Partnership received cash proceeds at closing of approximately $4.8 million and recorded a gain of less than $0.1 million. The Partnership used the proceeds received at closing to prepay revolving debt (without a commitment reduction).

6. DEBT

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

As of October 27, 2017, approximately $288.6 million of revolver borrowings and $1.5 million of letters of credit were outstanding under the credit agreement, leaving the Partnership with approximately $159.9 million available capacity for additional revolver borrowings and letters of credit under the credit agreement, although the Partnership's ability to borrow such funds may be limited by the financial covenants in the credit agreement. In connection with entering the amended and restated credit agreement, the Partnership paid certain upfront fees to the lenders thereunder, and the Partnership paid certain arrangement and other fees to the arranger and administrative agent of the credit agreement. The proceeds of loans made under the credit agreement may be used for working capital and other general partnership purposes of the Partnership. All references herein to the credit agreement on or after May 11, 2017, refer to the amended and restated credit agreement.

The credit agreement is guaranteed by all of the Partnership's existing subsidiaries. Obligations under the credit agreement are secured by first priority liens on substantially all of the Partnership's assets and those of the guarantors.

The credit agreement includes procedures for additional financial institutions to become revolving lenders, or for any existing lender to increase its revolving commitment thereunder, subject to an aggregate maximum of $600.0 million for all revolving loan commitments under the credit agreement.

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

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

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

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

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

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

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

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

- create, issue, incur or assume indebtedness;
- create, incur or assume liens;

- engage in mergers or acquisitions;
- sell, transfer, assign or convey assets;
- repurchase the Partnership’s equity, make distributions to unitholders and make certain other restricted payments;
- make investments;
- modify the terms of certain indebtedness, or prepay certain indebtedness;
- engage in transactions with affiliates;
- enter into certain hedging contracts;
- enter into certain burdensome agreements;
- change the nature of the Partnership’s business; and
- make certain amendments to the Partnership’s partnership agreement.

At September 30, 2017, the Partnership's consolidated total leverage ratio was 4.38 to 1.00 and the consolidated interest coverage ratio was 4.87 to 1.00. The Partnership was in compliance with all covenants of its credit agreement as of September 30, 2017.

The credit agreement permits the Partnership to make quarterly distributions of available cash (as defined in the Partnership's partnership agreement) to unitholders so long as no default or event of default exists under the credit agreement on a pro forma basis after giving effect to such distribution. The Partnership is currently allowed to make distributions to its unitholders in accordance with this covenant; however, the Partnership will only make distributions to the extent it has sufficient cash from operations after establishment of cash reserves as determined by the Board of Directors (the "Board") of the general partner in accordance with the Partnership's cash distribution policy, including the establishment of any reserves for the proper conduct of the Partnership's business. See Note 8 for additional information regarding distributions.

In addition to other customary events of default, the credit agreement includes an event of default if (i) the general partner ceases to own 100% of the Partnership's general partner interest or ceases to control the Partnership, or (ii) Ergon ceases to own and control 50.0% or more of the membership interests of the general partner, or (iii) during any period of 12 consecutive months, a majority of the members of the Board of the general partner ceases to be composed of individuals (A) who were members of the Board on the first day of such period, (B) whose election or nomination to the Board was approved by individuals referred to in clause (A) above constituting at the time of such election or nomination at least a majority of the Board or (C) whose election or nomination to the Board was approved by individuals referred to in clauses (A) and (B) above constituting at the time of such election or nomination at least a majority of the Board; provided that, any changes to the composition of individuals serving as members of the Board approved by Ergon will not cause an event of default.

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

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

Upon the execution of the amended and restated credit agreement, the Partnership expensed $0.7 million of debt issuance costs related to the prior revolving loan facility, leaving a remaining balance of $0.9 million ascribed to those lenders with commitments under both the prior and the amended and restated credit facility. The Partnership capitalized debt issuance costs of $0.9 million and $0.2 million during the three months ended September 30, 2016 and 2017, respectively. The Partnership capitalized debt issuance costs of $1.0 million and $4.2 million during the nine months ended September 30, 2016 and 2017, respectively. Debt issuance costs are being amortized over the term of the credit agreement. Interest expense related to debt issuance cost amortization for each of the three months ended September 30, 2016 and 2017, was $0.3 million. Interest expense related to debt issuance cost amortization for the nine months ended September 30, 2016 and 2017, was $0.8 million and $0.9 million, respectively.

During the three months ended September 30, 2016 and 2017, the weighted average interest rate under the Partnership's credit agreement was 4.27% and 4.54%, respectively, resulting in interest expense of approximately $2.8 million and $3.5 million, respectively. During the nine months ended September 30, 2016 and 2017, the weighted average interest rate under the Partnership's credit agreement, excluding the $0.7 million of debt issuance costs related to the prior credit facility that was expensed during the nine months ended September 30, 2017, was 3.92% and 4.36%, respectively, resulting in interest expense of approximately $8.0 million and $10.2 million, respectively.

During each of the three and nine months ended September 30, 2016 and 2017, the Partnership capitalized interest of less than $0.1 million.

The Partnership is exposed to market risk for changes in interest rates related to its credit facility. Interest rate swap agreements are used to manage a portion of the exposure related to changing interest rates by converting floating-rate debt to fixed-rate debt. As of December 31, 2016 and September 30, 2017, the Partnership had interest rate swaps with notional amounts totaling $200.0 million to hedge the variability of its LIBOR-based interest payments, with half maturing on June 28, 2018, and the other half maturing on January 28, 2019. During the three months ended September 30, 2016 and 2017, the

Partnership recorded swap interest expense of $0.6 million and $0.3 million, respectively. During the nine months ended September 30, 2016 and 2017, the Partnership recorded swap interest expense of $1.9 million and $1.1 million, respectively. The interest rate swaps do not receive hedge accounting treatment under ASC 815 - Derivatives and Hedging.

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

Derivatives not designated as hedging instruments:	Balance Sheet Location	Fair Values of Liability Derivative Instruments	
		December 31, 2016	September 30, 2017
Interest rate swaps - current	Current interest rate swaps liabilities	$—	$ 61
Interest rate swaps - noncurrent	Long-term interest rate swaps liabilities	$1,947	$ 633

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

Derivatives Not Designated as Hedging Instruments	Location of Gain (Loss) Recognized in Net Income on Derivative	Amount of Gain (Loss) Recognized in Net Income on Derivatives			
		Three Months ended September 30,		Nine Months ended September 30,	
		2016	2017	2016	2017
Interest rate swaps	Interest expense, net of capitalized interest	$1,308	$278	$(886)	$1,253

7. NET INCOME PER LIMITED PARTNER UNIT

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

	Three Months ended September 30,		Nine Months ended September 30,	
	2016	2017	2016	2017
Net income (loss)	$11,419	$9,771	$(6,791)	$19,684
General partner interest in net income	341	312	291	777
Preferred interest in net income	6,279	6,279	17,058	18,837
Net income (loss) available to limited partners	$4,799	$3,180	$(24,140)	$70
Basic and diluted weighted average number of units:				
Common units	36,036	38,189	34,139	38,164
Restricted and phantom units	876	922	799	845
Total units	36,912	39,111	34,938	39,009
Basic and diluted net income (loss) per common unit	$0.13	$0.08	$(0.69)	$—

8. PARTNERS' CAPITAL AND DISTRIBUTIONS

On October 5, 2016, the Partnership issued 847,457 common units to Ergon in a private placement for $5.0 million. In addition, on October 5, 2016, the Partnership repurchased 6,667,695 Series A Preferred Units from each of Vitol and Charlesbank for an aggregate purchase price of approximately $95.3 million. Vitol and Charlesbank each retained 2,488,789 Series A Preferred Units upon completion of these transactions. Also, on October, 5, 2016, the Partnership issued 18,312,968 Series A Preferred Units to Ergon for $144.7 million, as well as 97,654 general partner units to the Partnership's general partner for $0.7 million.

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

On October 18, 2017, the Board approved a distribution of $0.17875 per preferred unit, or a total distribution of $6.3 million, for the quarter ending September 30, 2017. The Partnership will pay this distribution on the preferred units on November 14, 2017, to unitholders of record as of November 3, 2017.

In addition, on October 18, 2017, the Board declared a cash distribution of $0.1450 per unit on its outstanding common units. The distribution will be paid on November 14, 2017, to unitholders of record on November 3, 2017. The distribution is for the three months ended September 30, 2017. The total distribution will be approximately $5.9 million, with approximately $5.5 million and $0.3 million to be paid to the Partnership's common unitholders and general partner, respectively, and $0.1 million to be paid to holders of phantom and restricted units pursuant to awards granted under the Partnership's long-term incentive plan.

9. RELATED PARTY TRANSACTIONS

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

The Partnership leases facilities to Ergon and also provides asphalt product and residual fuel terminalling services to Ergon. For the three months ended September 30, 2016 and 2017, the Partnership recognized total revenues of $4.5 million and $14.5 million, respectively, for services provided to Ergon. For the nine months ended September 30, 2016 and 2017, the Partnership recognized total revenues of $11.6 million and $41.3 million, respectively, for services provided to Ergon. For the three and nine months ended September 30, 2016, all Ergon revenues are classified as third party revenue, while revenues for the three and nine months ended September 30, 2017 are classified as related party revenue. As of December 31, 2016 and September 30, 2017, the Partnership had receivables from Ergon of $1.7 million and $2.0 million, respectively, net of allowance for doubtful accounts. As of December 31, 2016 and September 30, 2017, the Partnership had unearned revenues from Ergon of $1.0 million and $4.9 million, respectively.

The Partnership provides crude oil gathering, transportation, and terminalling services to Vitol. For the three months ended September 30, 2016, the Partnership recognized related party revenues of $5.4 million for services provided to Vitol. For the nine months ended September 30, 2016, the Partnership recognized related party revenues of $17.6 million for services provided to Vitol. All revenue from services provided to Vitol for the three and nine months ended September 30, 2017 is classified as third party revenue.

The Partnership provided operating and administrative services to Advantage Pipeline. On April 3, 2017, the Partnership sold its investment in Advantage Pipeline and the operating and administrative services agreement was terminated at closing. See Note 4 for additional information. For the three months ended September 30, 2016, the

Partnership earned revenues of $0.3 million for services provided to Advantage Pipeline. For the nine months ended September 30, 2016 and 2017, the Partnership earned revenues of $1.0 million and $0.3 million, respectively, for services provided to Advantage Pipeline. As of December 31, 2016, the Partnership had receivables from Advantage Pipeline of $0.1 million.

10. LONG-TERM INCENTIVE PLAN

In July 2007, the general partner adopted the Long-Term Incentive Plan (the “LTIP”). The compensation committee of the Board administers the LTIP. Effective April 29, 2014, the Partnership’s unitholders approved an amendment to the LTIP to increase the number of common units reserved for issuance under the incentive plan to 4,100,000 common units. The common units are deliverable upon vesting. Although other types of awards are contemplated under the LTIP, currently outstanding awards include “phantom” units, which convey the right to receive common units upon vesting, and “restricted” units, which are grants of common units restricted until the time of vesting. Certain of the phantom unit awards also include distribution equivalent rights (“DERs”).

Subject to applicable earning criteria, a DER entitles the grantee to a cash payment equal to the cash distribution paid on an outstanding common unit prior to the vesting date of the underlying award. Recipients of restricted units are entitled to receive cash distributions paid on common units during the vesting period which distributions are reflected initially as a reduction of partners’ capital. Distributions paid on units which ultimately do not vest are reclassified as compensation expense. Awards granted to date are equity awards and, accordingly, the fair value of the awards as of the grant date is expensed over the vesting period.

In connection with each anniversary of joining the Board, restricted common units are granted to the independent directors. The units vest in one-third increments over three years. The following table includes information on outstanding grants made to the directors under the LTIP:

Grant Date	Number of Units	Weighted Average Grant Date Fair Value(1)	Grant Date Total Fair Value (in thousands)
December 2016	10,950	$ 6.85	$ 75

(1) Fair value is the closing market price on the grant date of the awards.

The Partnership also grants phantom units to employees. These grants are equity awards under ASC 718 – Stock Compensation, and, accordingly, the fair value of the awards as of the grant date is expensed over the vesting period. The following table includes information on the outstanding grants:

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

(1) Fair value is the closing market price on the grant date of the awards.

The unrecognized estimated compensation cost of outstanding phantom and restricted units at September 30, 2017 was $2.5 million, which will be recognized over the remaining vesting period.

In September 2012, Mr. Mark Hurley was granted 500,000 phantom units under the LTIP upon his employment as the Chief Executive Officer of the general partner. These grants were equity awards under ASC 718 – Stock Compensation, and, accordingly, the fair value of the awards as of the grant date was expensed over the vesting period. These units vested ratably over five years pursuant to the Employee Phantom Unit Agreement between Mr. Hurley and the general partner and did not include DERs. The weighted average grant date fair value for the units of $5.62 was determined based on the closing market price of the Partnership’s common units on the grant date of the award, less the present value of the estimated distributions to be paid to holders of an outstanding common unit prior to the vesting of the underlying award. The value of this award grant was approximately $2.8 million on the grant date. The final portion of this award vested during September 2017, and there was no unrecognized estimated compensation cost as of September 30, 2017.

The Partnership's equity-based incentive compensation expense for the three months ended September 30, 2016 and 2017, was $0.7 million and $0.6 million, respectively. The Partnership's equity-based incentive compensation expense for the nine months ended September 30, 2016 and 2017 was $1.8 million and $1.7 million, respectively.

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

	Number of Units	Weighted Average Grant Date Fair Value
Nonvested at December 31, 2016	915,180	$ 6.61
Granted	323,339	7.15
Vested	313,923	7.96
Forfeited	3,684	7.74
Nonvested at September 30, 2017	920,912	$ 6.32

11. EMPLOYEE BENEFIT PLANS

Under the Partnership’s 401(k) Plan, which was instituted in 2009, employees who meet specified service requirements may contribute a percentage of their total compensation, up to a specified maximum, to the 401(k) Plan. The Partnership may match each employee’s contribution, up to a specified maximum, in full or on a partial basis. The Partnership recognized expense of $0.3 million for each of the three months ended September 30, 2016 and 2017, for discretionary contributions under the 401(k) Plan. The Partnership recognized expense of $0.9 million for each of the nine months ended September 30, 2016 and 2017, for discretionary contributions under the 401(k) Plan.

The Partnership may also make annual lump-sum contributions to the 401(k) Plan irrespective of the employee’s contribution match. The Partnership may make a discretionary annual contribution in the form of profit sharing calculated as a percentage of an employee’s eligible compensation. This contribution is retirement income under the qualified 401(k) Plan. Annual profit sharing contributions to the 401(k) Plan are submitted to and approved by the Board. The Partnership recognized expense of $0.2 million for each of the three months ended September 30, 2016 and 2017, for discretionary profit sharing contributions under the 401(k) Plan. The Partnership recognized expense of $0.5 million and $0.6 million during the nine months ended September 30, 2016 and 2017, respectively, for discretionary profit sharing contributions under the 401(k) Plan.

Under the Partnership’s Employee Unit Purchase Plan (the “Unit Purchase Plan”), which was instituted in January 2015, employees have the opportunity to acquire or increase their ownership of common units representing limited partner interests in the Partnership. Eligible employees who enroll in the Unit Purchase Plan may elect to have a designated whole percentage, up to a specified maximum, of their eligible compensation for each pay period withheld for the purchase of common units at a discount to the then current market value. A maximum of 1,000,000 common units may be delivered under the Unit Purchase Plan, subject to adjustment for a recapitalization, split, reorganization, or similar event pursuant to the terms of the Unit Purchase Plan. The Partnership recognized compensation expense of less than $0.1 million during each of the three and nine months ended September 30, 2016, and during the three months ended September 30, 2017, in connection with the Unit Purchase Plan. The Partnership recognized compensation expense of $0.1 million during the nine months ended September 30, 2017, in connection with the Unit Purchase Plan.

12. FAIR VALUE MEASUREMENTS

The Partnership uses valuation techniques, such as the market approach (comparable market prices), the income approach (present value of future income or cash flow), and the cost approach (cost to replace the service capacity of an asset or replacement cost) to value assets and liabilities required to be measured at fair value, as appropriate. The Partnership uses an exit price when determining the fair value. The exit price represents amounts that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants.

The Partnership utilizes a three-tier fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value into three broad levels. The following is a brief description of those three levels:

Level 1	Observable inputs such as quoted prices (unadjusted) in active markets for identical assets or liabilities.
Level 2	Inputs other than quoted prices that are observable for these assets or liabilities, either directly or indirectly. These include quoted prices for similar assets or liabilities in active markets and quoted prices for identical or similar assets or liabilities in markets that are not active.
Level 3	Unobservable inputs in which there is little market data, which requires the reporting entity to develop its own assumptions.

This hierarchy requires the use of observable market data, when available, to minimize the use of unobservable inputs when determining fair value. In periods in which they occur, the Partnership recognizes transfers into and out of Level 3 as of the end of the reporting period. There were no transfers during the nine months ended September 30, 2017. Transfers out of Level 3 represent existing assets and liabilities that were classified previously as Level 3 for which the observable inputs became a more significant portion of the fair value estimates. Determining the appropriate classification of the Partnership's fair value measurements within the fair value hierarchy requires management's judgment regarding the degree to which market data is observable or corroborated by observable market data.

The Partnership's recurring financial assets and liabilities subject to fair value measurements and the necessary disclosures are as follows (in thousands):

	Fair Value Measurements as of December 31, 2016			
Description	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Liabilities:				
Interest rate swap liabilities	$1,947	$ —	$ 1,947	$ —
Total	$1,947	$ —	$ 1,947	$ —

	Fair Value Measurements as of September 30, 2017			
Description	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Liabilities:				
Interest rate swap liabilities	$694	$ —	$ 694	$ —
Total	$694	$ —	$ 694	$ —

Fair Value of Other Financial Instruments

The following disclosure of the estimated fair value of financial instruments is made in accordance with accounting guidance for financial instruments. The Partnership has determined the estimated fair values by using available market information and valuation methodologies. Considerable judgment is required in interpreting market data to develop the estimates of fair value. The use of different market assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

At September 30, 2017, the carrying values on the unaudited condensed consolidated balance sheets for cash and cash equivalents (classified as Level 1), accounts receivable, and accounts payable approximate their fair value because of their short-term nature.

Based on the borrowing rates currently available to the Partnership for credit agreement debt with similar terms and maturities and consideration of the Partnership's non-performance risk, long-term debt associated with the Partnership's credit agreement at September 30, 2017 approximates its fair value. The fair value of the Partnership's long-term debt was calculated using observable inputs (LIBOR for the risk-free component) and unobservable company-specific credit spread information. As such, the Partnership considers this debt to be Level 3.

13. OPERATING SEGMENTS

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

ASPHALT TERMINALLING SERVICES —The Partnership provides asphalt product and residual fuel terminalling services, which includes storage, handling and blending services, at its 54 terminalling facilities located in 26 states.

CRUDE OIL TERMINALLING SERVICES —The Partnership provides crude oil terminalling services, which includes storage, handling and blending services, at its terminalling facility located in Oklahoma.

CRUDE OIL PIPELINE SERVICES —The Partnership owns and operates pipeline systems that gather crude oil purchased by its customers and transports it to refiners, to common carrier pipelines for ultimate delivery to refiners or to terminalling facilities owned by the Partnership and others. The Partnership refers to its pipeline system located in Oklahoma and the Texas Panhandle as the Mid-Continent system. The Partnership previously owned and operated the East Texas pipeline system, which is located in Texas. On April 18, 2017, the Partnership sold the East Texas system. See Note 5 for additional information.

CRUDE OIL TRUCKING AND PRODUCER FIELD SERVICES — The Partnership uses its owned and leased tanker trucks to gather crude oil for its customers at remote wellhead locations generally not covered by pipeline and gathering systems and to transport the crude oil to aggregation points and storage facilities located along pipeline gathering and transportation systems. Crude oil producer field services consist of a number of producer field services, ranging from gathering condensates from natural gas companies to hauling produced water to disposal wells.

The Partnership’s management evaluates performance based upon segment operating margin, which includes revenues from related parties and external customers less operating expenses, excluding depreciation and amortization. This measure forms the basis of the Partnership’s internal financial reporting and is used by its management in deciding how to allocate capital resources among segments. The Partnership believes that investors benefit from having access to the same financial measures being utilized by management. The non-GAAP measure of total operating margin, excluding depreciation and amortization, is presented in the following table. Total operating margin, excluding depreciation and amortization, is an important measure of the economic performance of the Partnership’s core operations. The Partnership computes the components of total operating margin by using amounts that are determined in accordance with GAAP. A reconciliation of total operating margin, excluding depreciation and amortization, to income before income taxes, which is its nearest comparable GAAP financial measure, is included in the following table. Income before income taxes, alternatively, includes expense items, such as depreciation and amortization, general and administrative expenses and interest expense, which management does not consider when evaluating the core profitability of the Partnership’s operations.

The following table reflects certain financial data for each segment for the periods indicated (in thousands):

	Three Months ended September 30,		Nine Months ended September 30,	
	2016	2017	2016	2017
Asphalt Terminalling Services				
Service revenue				
Third party revenue	$25,217	$17,690	$60,656	$44,172
Related party revenue	242	14,464	800	41,301
Total revenue for reportable segment	25,459	32,154	61,456	85,473
Operating expense, excluding depreciation and amortization	6,467	11,608	19,737	35,864
Segment operating margin	18,992	20,546	41,719	49,609
Total assets (end of period)	$114,703	$142,571	$114,703	$142,571
Crude Oil Terminalling Services				
Service revenue				
Third party revenue	$3,444	$5,162	$10,631	$17,013
Related party revenue	2,344	—	7,747	—
Total revenue for reportable segment	5,788	5,162	18,378	17,013
Operating expense, excluding depreciation and amortization	776	994	3,071	2,996
Segment operating margin	5,012	4,168	15,307	14,017
Total assets (end of period)	$74,807	$68,985	$74,807	$68,985
Crude Oil Pipeline Services				
Service revenue				
Third party revenue	$1,107	$2,196	$6,061	$7,520
Related party revenue	1,665	—	4,970	310
Product sales revenue				
Third party revenue	5,605	2,375	16,058	8,252
Total revenue for reportable segment	8,377	4,571	27,089	16,082
Operating expense, excluding depreciation and amortization	3,349	3,056	11,288	9,438
Operating expense (intersegment)	197	77	692	321
Cost of product sales	3,513	1,675	10,789	6,482
Cost of product sales (intersegment)	—	150	426	150
Segment operating margin	1,318	(387)	3,894	(309)
Total assets (end of period)	$151,341	$116,720	$151,341	$116,720
Crude Oil Trucking and Producer Field Services				
Service revenue				
Third party revenue	$5,832	$5,587	$19,363	$18,738
Related party revenue	1,483	—	5,088	—
Intersegment revenue	197	77	692	321
Product sales revenue				
Third party revenue	—	—	—	385
Intersegment revenue	—	150	426	150
Total revenue for reportable segment	7,512	5,814	25,569	19,594
Operating expense, excluding depreciation and amortization	7,051	6,042	23,771	20,013
Segment operating margin	461	(228)	1,798	(419)
Total assets (end of period)	$13,155	$9,781	$13,155	$9,781

16

	Three Months ended September 30,		Nine Months ended September 30,	
	2016	2017	2016	2017
Total operating margin, excluding depreciation and amortization[(1)]	$25,783	$24,099	$62,718	$62,898
Total segment revenues	$47,136	$47,701	$132,492	$138,162
Elimination of intersegment revenues	(197)	(227)	(1,118)	(471)
Consolidated revenues	$46,939	$47,474	$131,374	$137,691

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

	Three Months ended September 30,		Nine Months ended September 30,	
	2016	2017	2016	2017
Operating margin (excluding depreciation and amortization)	$25,783	$24,099	$62,718	$62,898
Depreciation and amortization	(7,624)	(7,680)	(22,447)	(23,586)
General and administrative expenses	(4,865)	(4,093)	(14,447)	(13,000)
Asset impairment expense	—	—	(22,845)	(45)
Gain (loss) on sale of assets	104	(107)	85	(986)
Equity earnings in unconsolidated affiliate	305	—	1,086	61
Gain on sale of unconsolidated affiliate	—	1,112	—	5,284
Interest expense	(2,175)	(3,500)	(10,742)	(10,795)
Income (loss) before income taxes	$11,528	$9,831	$(6,592)	$19,831

14. COMMITMENTS AND CONTINGENCIES

The Partnership is from time to time subject to various legal actions and claims incidental to its business. Management believes that these legal proceedings will not have a material adverse effect on the financial position, results of operations or cash flows of the Partnership. Once management determines that information pertaining to a legal proceeding indicates that it is probable that a liability has been incurred and the amount of such liability can be reasonably estimated, an accrual is established equal to its estimate of the likely exposure.

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

15. INCOME TAXES

The anticipated after-tax economic benefit of an investment in the Partnership's units depends largely on the Partnership being treated as a partnership for federal income tax purposes. If less than 90% of the gross income of a publicly traded partnership, such as the Partnership, for any taxable year is "qualifying income" from sources such as the transportation, storage, marketing (other than to end users), or processing of crude oil, natural gas or products thereof, rents from real property leased to unrelated parties, interest, dividends or certain other specified sources, that partnership will be taxable as a corporation under Section 7704 of the Internal Revenue Code for federal income tax purposes for that taxable year and all subsequent years.

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

The Partnership has entered into terminalling contracts with third party customers and leases with third party lessees with respect to all of its asphalt facilities. In the second quarter of 2009, the Partnership submitted a request for a ruling from the IRS that rental income from the leases constitutes "qualifying income." In October 2009, the Partnership received a favorable ruling from the IRS to the effect that rental income received under the leases with third party lessees constitutes qualifying income. As part of this ruling, however, the Partnership agreed to transfer, and has transferred, certain of its asphalt processing assets and related fee income to a subsidiary taxed as a corporation. This transfer occurred in the first quarter of 2010. Such subsidiary's income is subject to tax at the applicable federal, state and local income tax rates. Distributions from this subsidiary generally are taxed again to the Partnership's unitholders as corporate distributions and none of the income, gains, losses, deductions or credits of this subsidiary will flow through to the Partnership's unitholders.

In relation to the Partnership's taxable subsidiary, the tax effects of temporary differences between the tax basis of assets and liabilities and their financial reporting amounts at September 30, 2017, are presented below (dollars in thousands):

Deferred tax assets	
Difference in bases of property, plant and equipment	$780
Deferred tax asset	780
Less: valuation allowance	780
Net deferred tax asset	$—

The Partnership has considered the taxable income projections in future years, whether the carryforward period is so brief that it would limit realization of tax benefits, whether future revenue and operating cost projections will produce enough taxable income to realize the deferred tax asset based on existing service rates and cost structures, and the Partnership's earnings history exclusive of the loss that created the future deductible amount for the Partnership's subsidiary that is taxed as a corporation for purposes of determining the likelihood of realizing the benefits of the deferred tax assets. As a result of the Partnership's consideration of these factors, the Partnership has provided a full valuation allowance against its deferred tax asset as of September 30, 2017.

16. RECENTLY ISSUED ACCOUNTING STANDARDS

Except as discussed below and in the 2016 Annual Report on Form 10-K, there have been no new accounting pronouncements that have become effective or have been issued during the nine months ended September 30, 2017 that are of significance or potential significance to the Partnership.

In May 2014, the FASB issued ASU 2014-09, "Revenue from Contracts with Customers." The amendments in this update create Topic 606, Revenue from Contracts with Customers, and supersede the revenue recognition requirements in Topic 605, Revenue Recognition, including most industry-specific revenue recognition guidance throughout the Industry Topics of the Codification. In addition, the amendments supersede the cost guidance in Subtopic 605-35, Revenue Recognition-Construction-Type and Production-Type Contracts, and create new Subtopic 340-40, Other Assets and Deferred Costs-Contracts with Customers. In summary, the core principle of Topic 606 is that an entity recognizes revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services.

Throughout 2015 and 2016, the FASB has issued a series of subsequent updates to the revenue recognition guidance in Topic 606, including ASU No. 2015-14, Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date, ASU No. 2016-08, Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations (Reporting Revenue Gross versus Net), ASU No. 2016-10, Revenue from Contracts with Customers (Topic 606): Identifying Performance Obligations and Licensing, ASU No. 2016-12, Revenue from Contracts with Customers (Topic 606): Narrow-Scope Improvements and Practical Expedients, ASU No. 2016-20, Technical Corrections and Improvements to Topic 606, Revenue from Contracts with Customers, and ASU No. 2017-13, Amendments to SEC Paragraphs Pursuant to the Staff Announcement at the July 20, 2017 EITF Meeting and Rescission of Prior SEC Staff Announcements and Observer Comments.

The amendments in ASU 2014-09, ASU 2016-08, ASU 2016-10, ASU 2016-12, and ASU 2016-20 are effective for public entities for annual reporting periods beginning after December 15, 2017, and for interim periods within that reporting period. Early application is permitted for annual reporting periods beginning after December 15, 2016.

The Partnership is evaluating the impact of this standard, which will be adopted as of January 1, 2018.

- The Partnership is currently assessing implementation challenges, technical interpretations, industry-specific treatment of certain revenue contract types, and project status.
- The Partnership is currently reviewing contracts for each revenue stream identified within each of our business segments. Through this process, the Partnership is evaluating potential changes in revenue recognition upon adoption of the revised guidance.
- The Partnership is evaluating the potential information technology and internal control changes that will be required for adoption based on the findings of the contract review process.
- The Partnership plans to provide internal training and awareness related to the revised guidance to the key stakeholders throughout the organization.
- The Partnership is developing the required disclosures under the standard.

While the Partnership has tentatively concluded that the implementation of ASU 2014-09 will not have a material impact on the revenue recognition policies for a substantial number of contracts, management has identified several areas of potential impact through the contract review process currently underway, including accounting for non-cash consideration and the timing of revenue recognition with respect to deficiency payments in the crude oil pipeline services segment. The Partnership is in the process of quantifying the impact of adoption, but cannot reasonably estimate the full impact of the standard until the industry reaches consensus on these issues. The Partnership is currently evaluating potential changes to disclosures based on the additional requirements prescribed by the standard. These new disclosures include information regarding the significant judgments used in evaluating when and how revenue is (or will be) recognized and data related to contract assets and liabilities. Additionally, the Partnership is evaluating the business processes, systems, and controls to ensure the accuracy and timeliness of the recognition and disclosure requirements under the new revenue guidance.

The Partnership will continue to conduct the contract review process throughout 2017 and, as a result, additional areas of impact may be identified. The Partnership expects to adopt the new standard on January 1, 2018, using the modified retrospective approach. This approach allows for applying the new standard to (i) all new contracts entered into after January 1, 2018, and (ii) all existing contracts for which all (or substantially all) of the revenue has not been recognized under legacy revenue guidance as of January 1, 2018, through a cumulative adjustment to equity. Consolidated revenues presented in the comparative financial statements for periods prior to January 1, 2018, would not be revised.

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

In February 2016, the FASB issued ASU 2016-02, “Leases (Topic 842).” This update introduces a new lease model that requires the recognition of lease assets and lease liabilities on the balance sheet and the disclosure of key information about leasing arrangements. This update is effective for financial statements issued for annual periods beginning after December 15, 2018, and interim periods within those fiscal years. In 2017, the FASB issued an update to the lease guidance, ASU No. 2017-13, Amendments to SEC Paragraphs Pursuant to the Staff Announcement at the July 20, 2017 EITF Meeting and Rescission of Prior SEC Staff Announcements and Observer Comments. The Partnership is in the process of reviewing its catalog of leases and analyzing each lease to assess the impact of this guidance, which will be adopted beginning with the Partnership's quarterly report for the period ending March 31, 2019.

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

In February 2017, the FASB issued ASU 2017-05, "Other Income - Gains and Losses from the Derecognition of Nonfinancial Assets (Subtopic 610-20)." This update clarifies the scope of Subtopic 610-20 and adds guidance for partial sales of nonfinancial assets. Subtopic 610-20, which was issued in May 2014 as a part of Accounting Standards Update No. 2014-09, Revenue from Contracts with Customers (Topic 606), provides guidance for recognizing gains and losses from the transfer of nonfinancial assets in contracts with noncustomers. The amendments in ASU 2017-05 are effective for public entities for annual reporting periods beginning after December 15, 2017, and for interim periods within that reporting period. Early application is permitted for annual reporting periods beginning after December 15, 2016. The Partnership is evaluating the impact of this standard on us, which will be adopted beginning with the Partnership’s quarterly report for the period ending March 31, 2018.

In May 2017, the FASB issued ASU 2017-09, “Compensation - Stock Compensation (Topic 718) Scope of Modification Accounting.” This update provides clarity and reduces both diversity in practice and cost and complexity when applying the guidance of Topic 718, Compensation - Stock Compensation, to a change in the terms or conditions of a share-based payment award. This update is effective for financial statements issued for annual periods beginning after December 15, 2017, and interim periods within those fiscal years. The Partnership is evaluating the impact of this guidance, which will be adopted beginning with the Partnership’s quarterly report for the period ending March 31, 2018.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

As used in this quarterly report, unless we indicate otherwise: (1) "Blueknight Energy Partners," "the Partnership," "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) and (4) Vitol refers to Vitol Holding B.V., its affiliates and subsidiaries. The following discussion analyzes the historical financial condition and results of operations of the Partnership and should be read in conjunction with our financial statements and notes thereto, and Management's Discussion and Analysis of Financial Condition and Results of Operations presented in our Annual Report on Form 10-K for the year ended December 31, 2016, which was filed with the Securities and Exchange Commission (the "SEC") on March 9, 2017 (the "2016 Form 10-K").

Forward-Looking Statements

This report contains forward-looking statements. Statements included in this quarterly 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), including, without limitation, the information set forth in this Management's Discussion and Analysis of Financial Condition and Results of Operations, 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 statements 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 the filing of this report. Although we believe that the expectations reflected in these forward-looking statements are based on reasonable assumptions, no assurance can be given that these expectations will prove to be correct. Important factors that could cause our actual results to differ materially from the expectations reflected in these forward-looking statements include, among other things, those set forth in "Part I, Item 1A. Risk Factors" in the 2016 Form 10-K.

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.

Overview

We are a publicly traded master limited partnership with operations in 26 states. We provide integrated terminalling, gathering and transportation services for companies engaged in the production, distribution and marketing of liquid asphalt cement 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 Matters 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 October 27, 2017, the price per barrel was approximately $54). Also, 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). Recently, however, the crude oil price curve has been relatively flat (in which the current crude oil price per barrel is relatively equal to the future price per barrel and there is no clear incentive to store or transport product). 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 market price for crude oil, decreased production in areas in which we serve, decreased demand for transportation capacity and an increased cost of capital. We expect these changes to have the following near-term impacts:

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 investment. As a result, we do not expect recent 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 terminalling business as crude oil marketers are incentivized to store crude oil during the current month and sell into the future month. In September 2014, we had approximately 4.8 million barrels of storage with contracts that had expired or would expire between September 30, 2014 and May 31, 2015. 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 and have since leveled out. We have approximately 0.6 million barrels of storage with contracts that expire during the fourth quarter of 2017 and an additional 4.6 million barrels of crude oil contracts that expire in 2018. A change in the crude oil futures pricing curve from contango to backwardated or a relatively flat price curve combined with a relatively low market price per barrel may impact our ability to recontract expiring contracts or the rate upon which they are recontracted.

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 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 system and concurrently reversed the Eagle North system.

We are currently operating one Oklahoma mainline system, which is a combination of the Mid-Continent and Eagle North systems, instead of two separate systems, providing us with a current capacity of approximately 20,000 to 25,000 barrels per day ("Bpd"). We are working to restore service of the second Oklahoma pipeline system and expect to put the line back in service with a capacity of approximately 20,000 Bpd during the second quarter of 2018. 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.

We experienced a decrease in revenue on our East Texas 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. 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 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 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.

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. We expect to receive up to approximately $2.2 million for our pro rata portion of the remaining net escrow proceeds in January 2018.

The Knight Warrior project, the East Texas Eaglebine/Woodbine crude oil pipeline 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 have been canceled. In connection with the cancellation of the shipper commitments, we evaluated the Knight Warrior project for impairment and recognized an impairment expense of $22.6 million in June 2016.

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 began decreasing. We continue to experience increased competition in this segment, which has resulted in further pressures on the rates we are able to charge our customers for services provided.

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. For the three and nine months ended September 30, 2017, we recognized revenues of $14.5 million and $41.3 million, respectively, for services provided to Ergon. For the nine months ended September 30, 2017, we recognized revenues of $0.3 million for services provided to Advantage Pipeline. The remainder of our services were provided to unrelated third parties for the nine months ended September 30, 2017.

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

We have leases and terminalling agreements for all of our 54 asphalt facilities. We operate the asphalt facilities pursuant to the terminalling agreements, while our contract counterparties operate the asphalt facilities that are subject to the lease agreements.

As of October 27, 2017, we had approximately 6.0 million barrels of crude oil storage under service contracts with remaining terms ranging from one month to 50 months, including 0.6 million barrels of crude oil storage contracts that expire in the fourth quarter of 2017 and an additional 4.6 million barrels of crude oil contracts that expire in 2018. Storage contracts with Vitol represent 2.2 million barrels of crude oil storage capacity under contract. We are in negotiations to either extend contracts with existing customers or enter into new customer contracts for the storage capacity expiring in 2017; however, there is no certainty that we will have success in contracting available capacity or that extended or new contracts will be at the same or similar rates as the expiring contracts. If we are unable to renew the majority of the expiring storage contracts, we may experience lower utilization of our assets which could have a material adverse effect on our business, cash flows, ability to make distributions to our unitholders, the price of our common units, results of operations and ability to conduct our business.

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 three months ended September 30, 2017, we transported approximately 21,000 barrels per day on our Mid-Continent pipeline system, which is an increase of 17% compared to the three months ended September 30, 2016. During the nine months ended September 30, 2017, we transported approximately 22,000 barrels per day on our Mid-Continent pipeline system, which is a decrease of 24% compared to the nine months ended September 30, 2016. We are currently operating one Oklahoma mainline system, 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 with a capacity of approximately 20,000 Bpd during the second quarter of 2018. See Crude oil pipeline services segment within our results of operations discussion for additional detail. Vitol accounted for 57% and 39% of volumes transported in our pipelines in the three months ended September 30, 2017 and 2016, respectively. Vitol accounted for 57% and 28% of volumes transported in our pipelines in the nine months ended September 30, 2017 and 2016, respectively.

For the three months ended September 30, 2017, we transported approximately 20,000 barrels per day on our crude oil transport trucks, a decrease of 20% as compared to the three months ended September 30, 2016. For the nine months ended September 30, 2017, we transported approximately 21,000 barrels per day on our crude oil transport trucks, a decrease of 25% as compared to the nine months ended September 30, 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 with a capacity of approximately 20,000 Bpd during 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. Vitol accounted for approximately 40% and 32% of volumes transported by our crude oil transport trucks in the three months ended September 30, 2017 and 2016, respectively. Vitol accounted for approximately 48% and 29% of volumes transported by our crude oil transport trucks in the nine months ended September 30, 2017 and 2016, respectively. The decrease in transported volumes is attributable to increased competition and lower crude oil production volume in the areas we serve.

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 product 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 14% for the nine months ended September 30, 2017 as compared to the nine months ended September 30, 2016. This is primarily a result of the acquisition of the nine asphalt terminals from Ergon in October 2016. Decreases in general and administrative expenses for the nine months ended September 30, 2017 as compared to the nine months ended September 30, 2016 were primarily due to expenses incurred in 2016 related to the Ergon Transactions (as defined in Note 1 to our unaudited condensed consolidated financial statements). Our interest expense increased by $0.1 million for the nine months ended September 30, 2017 as compared to the nine months ended September 30, 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.

Income Taxes

As part of the process of preparing the unaudited condensed 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 unaudited condensed 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. Unless we believe that recovery is more likely than not, 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 unaudited condensed 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 September 30, 2017.

Distributions

The amount of distributions we pay and the decision to make any distribution is determined by the Board of Directors of our general partner (the “Board”), which has broad discretion to establish cash reserves for the proper conduct of our business and for future distributions to our unitholders. In addition, our cash distribution policy is subject to restrictions on distributions under our credit facility.

On October 18, 2017, the Board approved a distribution of $0.17875 per preferred unit, or a total distribution of $6.3 million, for the quarter ending September 30, 2017. We will pay this distribution on the preferred units on November 14, 2017, to unitholders of record as of November 3, 2017.

In addition, on October 18, 2017, the Board approved a cash distribution of $0.1450 per unit on our outstanding common units. The distribution will be paid on November 14, 2017, to unitholders of record on November 3, 2017. The distribution is for the three months ended September 30, 2017. The total distribution to be paid is approximately $5.9 million, with approximately $5.5 million and $0.3 million paid to our common unitholders and general partner, respectively, and $0.1 million paid to holders of phantom and restricted units pursuant to awards granted under our long-term incentive plan.

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 segment operating margin, which includes revenues from related parties and external customers less operating expenses 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 unaudited condensed consolidated financial statements and footnotes.

The table below summarizes our financial results for the three months ended September 30, 2016 and 2017, reconciled to the most directly comparable GAAP measure:

Operating results	Three Months ended September 30,		Nine Months ended September 30,		Favorable/(Unfavorable)			
					Three Months		Nine Months	
(dollars in thousands)	2016	2017	2016	2017	$	%	$	%
Operating margin, excluding depreciation and amortization:								
Asphalt terminalling services operating margin	$18,992	$20,546	$41,719	$49,609	$1,554	8 %	$7,890	19 %
Crude oil terminalling services operating margin	5,012	4,168	15,307	14,017	(844)	(17)%	(1,290)	(8)%
Crude oil pipeline services operating margin	1,318	(387)	3,894	(309)	(1,705)	(129)%	(4,203)	(108)%
Crude oil trucking and producer field services operating margin	461	(228)	1,798	(419)	(689)	(149)%	(2,217)	(123)%
Total operating margin, excluding depreciation and amortization	25,783	24,099	62,718	62,898	(1,684)	(7)%	180	— %
Depreciation and amortization	(7,624)	(7,680)	(22,447)	(23,586)	(56)	(1)%	(1,139)	(5)%
General and administrative expense	(4,865)	(4,093)	(14,447)	(13,000)	772	16 %	1,447	10 %
Asset impairment expense	—	—	(22,845)	(45)	—	— %	22,800	100 %
Gain (loss) on sale of assets	104	(107)	85	(986)	(211)	(203)%	(1,071)	(1,260)%
Operating income	13,398	12,219	3,064	25,281	(1,179)	(9)%	22,217	725 %
Other income (expense):								
Equity earnings in unconsolidated affiliate	305	—	1,086	61	(305)	(100)%	(1,025)	(94)%
Gain on sale of unconsolidated affiliate	—	1,112	—	5,284	1,112	N/A	5,284	N/A
Interest expense	(2,175)	(3,500)	(10,742)	(10,795)	(1,325)	(61)%	(53)	— %
Provision for income taxes	(109)	(60)	(199)	(147)	49	45 %	52	26 %
Net income (loss)	$11,419	$9,771	$(6,791)	$19,684	$(1,648)	(14)%	$26,475	390 %

For the three and nine months ended September 30, 2017, operating margin, excluding depreciation and amortization, increased in our asphalt terminalling segment primarily as a result of acquisitions of eleven asphalt terminals in 2016. These increases were offset by lower operating margins in our other segments. Crude oil terminalling services operating margin decreased primarily due to decreased throughput fees as lower volumes were transferred in and out of our facilities. The decrease in crude oil pipeline services margin resulted from the suspended service on our Mid-Continent pipeline system due to a discovery of a pipeline exposure in April 2016 as well as the sale of our East Texas pipeline system in April 2017. Crude oil trucking and producer field services operating margin, excluding depreciation and amortization, decreased due to continued pressure on trucking and producer field service rates resulting from the decline in crude oil prices and a decrease in transported volumes.

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

Analysis of Operating Segments

Asphalt terminalling services segment

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

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

Operating results	Three Months ended September 30,		Nine Months ended September 30,		Favorable/(Unfavorable)			
					Three Months		Nine Months	
(dollars in thousands)	2016	2017	2016	2017	$	%	$	%
Service revenue:								
Third party revenue	$25,217	$17,690	$60,656	$44,172	$(7,527)	(30)%	$(16,484)	(27)%
Related party revenue	242	14,464	800	41,301	14,222	5,877 %	40,501	5,063 %
Total revenue	25,459	32,154	61,456	85,473	6,695	26 %	24,017	39 %
Operating expense (excluding depreciation and amortization)	6,467	11,608	19,737	35,864	(5,141)	(79)%	(16,127)	(82)%
Operating margin (excluding depreciation and amortization)	$18,992	$20,546	$41,719	$49,609	$1,554	8 %	$7,890	19 %

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

- Overall revenues have increased for the three and nine months ended September 30, 2017, as compared to the three and nine months ended September 30, 2016 primarily due to the acquisition of nine asphalt facilities from Ergon in October 2016 in addition to two asphalt terminals acquired in February 2016 from unrelated third parties. Also in October 2016, Ergon acquired our general partner, resulting in all revenues generated from services provided to Ergon after October 5, 2016 being classified as related party revenues when they were previously classified as third party.

- Operating expenses also increased for the three and nine months ended September 30, 2017, as compared to the three and nine months ended September 30, 2016 primarily due to the acquisitions noted above. In addition, operating expenses for the three and nine months ended September 30, 2017 increased by $0.8 million and $2.3 million as compared to the three and nine months ended September 30, 2016 as a result of two facilities we previously leased converting to operated facilities.

Crude oil terminalling services segment

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

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

Operating results	Three Months ended September 30,		Nine Months ended September 30,		Favorable/(Unfavorable)			
					Three Months		Nine Months	
(dollars in thousands)	2016	2017	2016	2017	$	%	$	%
Service revenue:								
Third party revenue	$3,444	$5,162	$10,631	$17,013	$1,718	50 %	$6,382	60 %
Related party revenue	2,344	—	7,747	—	(2,344)	(100)%	(7,747)	(100)%
Total revenue	5,788	5,162	18,378	17,013	(626)	(11)%	(1,365)	(7)%
Operating expense (excluding depreciation and amortization)	776	994	3,071	2,996	(218)	(28)%	75	2 %
Operating margin (excluding depreciation and amortization)	$5,012	$4,168	$15,307	$14,017	$(844)	(17)%	$(1,290)	(8)%
Average crude oil stored per month at our Cushing terminal (in thousands of barrels)	5,604	5,124	5,620	5,520	(480)	(9)%	(100)	(2)%
Average crude oil delivered to our Cushing terminal (in thousands of barrels per day)	69	27	83	40	(42)	(61)%	(43)	(52)%

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

- Revenues have moved from related party to third party due to Ergon acquiring our general partner in October 2016, at which time Vitol ceased to be a related party. Total revenues for the three and nine months ended September 30, 2017 have decreased due to a decrease in market rates for short-term, monthly storage contracts and decreased throughput fees as lower volumes were transferred in and out of our facilities.

- Operating expenses for the three and nine months ended September 30, 2017, increased as compared to the three and nine months ended September 30, 2016, primarily as a result of increases in property taxes.

- As of October 27, 2017, we had approximately 6.0 million barrels of crude oil storage under service contracts with remaining terms of up to 50 months, including 0.6 million barrels of crude oil storage contracts that expire in 2017 and an additional 4.6 million barrels of crude oil contracts that expire in 2018.

Crude oil pipeline services segment

Our crude oil pipeline services segment operations include both service and product sales revenue. Service revenue generally consists of tariffs and other fees associated with transporting crude oil products on pipelines. Product sales revenue is 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.

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

Operating results	Three Months ended September 30,		Nine Months ended September 30,		Favorable/(Unfavorable)			
					Three Months		Nine Months	
(dollars in thousands)	2016	2017	2016	2017	$	%	$	%
Service revenue:								
Third party revenue	$1,107	$2,196	$6,061	$7,520	$1,089	98 %	$1,459	24 %
Related party revenue	1,665	—	4,970	310	(1,665)	(100)%	(4,660)	(94)%
Product sales revenue:								
Third party revenue	5,605	2,375	16,058	8,252	(3,230)	(58)%	(7,806)	(49)%
Total revenue	8,377	4,571	27,089	16,082	(3,806)	(45)%	(11,007)	(41)%
Operating expense (excluding depreciation and amortization)	3,349	3,056	11,288	9,438	293	9 %	1,850	16 %
Operating expense (intersegment)	197	77	692	321	120	61 %	371	54 %
Cost of product sales	3,513	1,675	10,789	6,482	1,838	52 %	4,307	40 %
Cost of product sales (intersegment)	—	150	426	150	(150)	— %	276	65 %
Operating margin (excluding depreciation and amortization)	$1,318	$(387)	$3,894	$(309)	$(1,705)	(129)%	$(4,203)	(108)%
Average throughput volume (in thousands of barrels per day)								
Mid-Continent	18	21	29	22	3	17 %	(7)	(24)%
East Texas	10	—	11	1	(10)	(100)%	(10)	(91)%

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

- Revenues have moved from related party to third party due to Ergon’s acquisition of our general partner in October 2016, at which time Vitol ceased to be a related party.

- Included in product sales revenue for the three and nine months ended September 30, 2016, is $1.6 million and $3.2 million, respectively, in sales of crude oil arising from accumulated product-loss allowances (“PLA”). Product sales revenue for the three and nine months ended September 30, 2017, included $0.2 million and $0.3 million, respectively, in PLA sales.

- On April 18, 2017, we sold the East Texas pipeline system. We received cash proceeds at closing of approximately $4.8 million and recorded a gain of less than $0.1 million. The sale of the East Texas pipeline system has resulted in decreased revenues of $0.7 million and $1.7 million for the three and nine months ended September 30, 2017, respectively, as compared to the three and nine months ended September 30, 2016.

- For the nine months ended September 30, 2017, revenues were negatively impacted by the suspended service on our Mid-Continent pipeline system due to pipeline exposure caused by heavy rains and the erosion of a riverbed in southern Oklahoma discovered in late April 2016. There was no damage to the pipe and no loss of product. In the second quarter of 2016, we took action to mitigate the service suspension and worked with customers to divert volumes, and, in certain circumstances, transported volumes to a third-party pipeline system via truck. In addition, the term of the throughput and deficiency agreement on our Eagle North system expired on 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 system and concurrently reversed the Eagle North system. This enabled us to recapture diverted volumes and deliver those barrels to Cushing, Oklahoma. We are currently operating one Oklahoma mainline system, 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 with a capacity of approximately 20,000 Bpd during the second quarter of 2018. 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.

- For the three and nine months ended September 30, 2017, operating expenses have decreased by $0.5 million and $1.5 million, respectively, compared to the same periods in 2016 as a result of the sale of the East Texas pipeline system and the sale of our investment in Advantage Pipeline, for which we provided operational and administrative services through August 1, 2017.

Crude oil trucking and producer field services segment

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

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

Operating results	Three Months ended September 30,		Nine Months ended September 30,		Favorable/(Unfavorable)			
					Three Months		Nine Months	
(dollars in thousands)	2016	2017	2016	2017	$	%	$	%
Service revenue:								
Third party revenue	$5,832	$5,587	$19,363	$18,738	$(245)	(4)%	$(625)	(3)%
Related party revenue	1,483	—	5,088	—	(1,483)	(100)%	(5,088)	(100)%
Intersegment revenue	197	77	692	321	(120)	(61)%	(371)	(54)%
Product sales revenue:								
Third party revenue	—	—	—	385	—	—%	385	N/A
Intersegment revenue	—	150	426	150	150	—%	(276)	(65)%
Total revenue	7,512	5,814	25,569	19,594	(1,698)	(23)%	(5,975)	(23)%
Operating expense (excluding depreciation and amortization)	7,051	6,042	23,771	20,013	1,009	14%	3,758	16%
Operating margin (excluding depreciation and amortization)	$461	$(228)	$1,798	$(419)	$(689)	(149)%	$(2,217)	(123)%
Average volume (in thousands of barrels per day)	25	20	28	21	(5)	(20)%	(7)	(25)%

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

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

- Revenues have moved from related party to third party due to Ergon’s acquisition of our general partner in October 2016, at which time Vitol ceased to be a related party.

- Product sales revenues for the nine months ended September 30, 2017, are the result of a crude oil sale in our field services business to a third party. Intersegment product sales revenues for all periods are the result of crude oil sales in our field services business to our crude oil pipeline services segment.

Other Income and Expenses

Depreciation and amortization expense. Depreciation and amortization decreased by $0.1 million to $7.7 million for the three months ended September 30, 2017, compared to $7.6 million for the three months ended September 30, 2016. Depreciation and amortization increased by $1.1 million to $23.6 million for the nine months ended September 30, 2017, compared to $22.4 million for the nine months ended September 30, 2016. These changes in depreciation and amortization are primarily the result of asphalt terminal acquisitions made during the past two years offset by sales of assets, including the sale of the East Texas pipeline system.

General and administrative expenses. General and administrative expenses decreased to $4.1 million for the three months ended September 30, 2017, compared to $4.9 million for the three months ended September 30, 2016. General and administrative expenses decreased to $13.0 million for the nine months ended September 30, 2017, compared to $14.4 million for the nine months ended September 30, 2016. These decreases were primarily due to $0.9 million and $1.4 million of expenses incurred in the three and nine months ended September 30, 2016, respectively, related to the Ergon Transactions.

Asset impairment expense. There were no asset impairment expenses for the three months ended September 30, 2017 and 2016, respectively. Asset impairment expense was less than $0.1 million and $22.8 million for the nine months ended September 30, 2017 and 2016, respectively. During the second quarter of 2016, we recorded fixed asset impairment expense of $22.6 million due to an impairment recognized on the Knight Warrior project. The Knight Warrior project was canceled due to continued low rig counts in the Eaglebine/Woodbine area coupled with lower production volumes, competing projects and the overall impact of the decreased market price of crude oil. Consequently, shipper commitments related to the project were canceled. In connection with the cancellation of the shipper commitments, we evaluated the Knight Warrior project for impairment and recognized an impairment expense of $22.6 million during the second quarter of 2016.

Gain (loss) on sale of assets. We recognized a loss on the sale of assets of $0.1 million for the three months ended September 30, 2017, compared to a gain on the sale of assets of less than $0.1 million for the three months ended September 30, 2016. Loss on sale of assets was $1.0 million for the nine months ended September 30, 2017 compared to a gain of less than $0.1 million for the nine months ended September 30, 2016. Losses for the nine months ended September 30, 2017, include $0.4 million related to the disposal of an asphalt tank floor that had to be prematurely replaced due to corrosion. Additional losses for the period relate to the sale of assets no longer utilized, including land purchased for the canceled Knight Warrior project. Gains and losses in 2016 were primarily comprised of sales of surplus, used property and equipment.

In addition, 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.

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

Interest expense. Interest expense represents interest on borrowings under our credit facility as well as amortization of debt issuance costs and unrealized gains and losses related to the change in fair value of interest rate swaps.

Total interest expense for the three months ended September 30, 2017 increased by $1.3 million compared to the three months ended September 30, 2016. During the three months ended September 30, 2017, we recorded unrealized gains of $0.3 million due to the change in fair value of interest rate swaps compared to unrealized gains of $1.3 million during the three months ended September 30, 2016. Interest on our credit facility increased by $0.7 million due to increases in our average debt outstanding and the weighted average interest rate under our credit agreement. Also included in interest expense is the amortization of debt issuance costs of $0.3 million for each of the three months ended September 30, 2017 and 2016. Monthly interest payments on the interest rate swaps totaled $0.3 million and $0.6 million for the three months ended September 30, 2017 and 2016, respectively.

Total interest expense for the nine months ended September 30, 2017 increased by $0.1 million compared to the nine months ended September 30, 2016. During the nine months ended September 30, 2017, we recorded unrealized gains of $1.3 million due to the change in fair value of interest rate swaps compared to unrealized losses of $0.9 million during the nine months ended September 30, 2016. This decrease in interest expense was offset by increased interest on our credit facility of $2.2 million due to increases in our average debt outstanding and the weighted average interest rate under our credit agreement. Also included in interest expense is the amortization of debt issuance costs of $0.9 million and $0.8 million for the nine months ended September 30, 2017 and 2016, respectively, and an additional $0.7 million related to debt issuance costs that was written off due to the credit facility refinancing in May 2017. Monthly interest payments on the interest rate swaps totaled $1.1 million and $1.9 million for the nine months ended September 30, 2017 and 2016, respectively.

Effects of Inflation

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

Off Balance Sheet Arrangements

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

Liquidity and Capital Resources

Cash Flows and Capital Expenditures

The following table summarizes our sources and uses of cash for the nine months ended September 30, 2016 and 2017:

	Nine Months ended September 30,	
	2016	2017
	(in millions)	
Net cash provided by operating activities	$39.9	$46.2
Net cash provided by (used in) investing activities	$(33.1)	$22.3
Net cash used in financing activities	$(5.5)	$(69.2)

Operating Activities. Net cash provided by operating activities increased to $46.2 million for the nine months ended September 30, 2017, as compared to $39.9 million for the nine months ended September 30, 2016 due to increased net income as discussed in additional detail in our “Results of Operations” above as well as changes in working capital balances.

Investing Activities. Net cash provided by investing activities was $22.3 million for the nine months ended September 30, 2017, as compared to $33.1 million of net cash used in investing activities for the nine months ended September 30, 2016. We received proceeds of $26.4 million from our sale of Advantage Pipeline and $9.2 million from sales of other assets, including our East Texas pipeline system, during the nine months ended September 30, 2017. We acquired two asphalt terminalling facilities for $19.0 million during the nine months ended September 30, 2016. Capital expenditures for the nine months ended September 30, 2017 and 2016 included expansion capital expenditures of $6.7 million and $8.1 million, respectively, and gross maintenance capital expenditures of $6.6 million and $7.5 million, respectively.

Financing Activities. Net cash used in financing activities was $69.2 million for the nine months ended September 30, 2017, as compared to $5.5 million for the nine months ended September 30, 2016. Cash used in financing activities for the nine months ended September 30, 2017 consisted primarily of $36.9 million in distributions to our unitholders, as well as net payments on long-term debt of $26.4 million. Net cash used in financing activities for the nine months ended September 30, 2016 consisted primarily of $32.5 million in distributions to our unitholders partially offset by net borrowings on long-term debt of $9.0 million and proceeds from equity issuances of $21.3 million.

Our Liquidity and Capital Resources

Cash flows from operations and our credit facility are our primary sources of liquidity. At September 30, 2017, we had a working capital deficit of $3.5 million. This is primarily a function of our approach to cash management.

At September 30, 2017, we had approximately $150.9 million of availability under our credit facility, and we could borrow up to $324.4 million, or an additional $25.3 million, and still remain within our covenant restrictions. As of October 27, 2017, we have cash on hand of approximately $2.0 million and aggregate unused commitments under our revolving credit facility of approximately $159.9 million. Any incremental borrowings under our credit facility will be subject to covenant limitations. The credit agreement is scheduled to mature on May 11, 2022.

Capital Requirements. Our capital requirements consist of the following:

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

Expansion capital expenditures for organic growth projects, net of reimbursable expenditures of approximately $0.5 million, totaled $6.2 million in the nine months ended September 30, 2017, compared to $8.0 million, net of reimbursable expenditures of approximately $0.1 million, in the nine months ended September 30, 2016. We currently expect our expansion capital expenditures for organic growth projects to be approximately $8.0 million to $10.0 million for all of 2017. Maintenance capital expenditures totaled $6.1 million, net of reimbursable expenditures of approximately $0.5 million, in the nine months ended September 30, 2017, compared to $5.9 million, net of reimbursable expenditure of approximately $1.7 million, in the nine months ended September 30, 2016. We currently expect maintenance capital expenditures to be approximately $8.0 million to $9.0 million, net of reimbursable expenditures, for all of 2017.

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

Recent Accounting Pronouncements

For information regarding recent accounting developments that may affect our future financial statements, see Note 16 to our unaudited condensed consolidated financial statements.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

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

As of October 27, 2017, we had $288.6 million outstanding under our credit facility that was subject to a variable interest rate. Borrowings under our credit agreement bear interest, at our option, at either the reserve adjusted eurodollar rate (as defined in the credit agreement) plus an applicable margin or the alternate base rate (the highest of the agent bank's prime rate, the federal funds effective rate plus 0.5%, and the 30-day eurodollar rate plus 1.0%) plus an applicable margin. Interest rate swap agreements are used to manage a portion of the exposure related to changing interest rates by converting floating-rate debt to fixed-rate debt. As of September 30, 2017 and December 31, 2016, the Partnership had three interest rate swaps with notional amounts totaling $200.0 million to hedge the variability of its LIBOR-based interest payments. Under the terms of the settlement agreements, we pay fixed rates of 1.48%, 2.00% and 1.97% on notional amounts of $100.0 million, $60.0 million and $40.0 million, respectively. On all of the agreements, we receive one-month LIBOR with monthly settlement. The fair market value of the interest rate swaps at September 30, 2017 is a liability of $0.7 million and is recorded in either current or long-term interest rate swap liabilities, according to the maturity date, on the unaudited condensed consolidated balance sheets. The interest rate swaps do not receive hedge accounting treatment under ASC 815 - Derivatives and Hedging. Changes in the fair value of the interest rate swaps are recorded in interest expense in the unaudited condensed consolidated statements of operations.

During the nine months ended September 30, 2017, the weighted average interest rate under our credit agreement was 4.36%.

Changes in economic conditions could result in higher interest rates, thereby increasing our interest expense and reducing our funds available for capital investment, operations or distributions to our unitholders. Based on borrowings as of September 30, 2017, the terms of our credit agreement, current interest rates and the effect of our interest rate swaps, an increase or decrease of 100 basis points in the interest rate would result in increased or decreased annual interest expense of approximately $1.0 million.

Item 4. Controls and Procedures

Evaluation of disclosure controls and procedures. Our general partner's management, including the Chief Executive Officer and Chief Financial Officer of our general partner, evaluated, as of the end of the period covered by this report, the effectiveness of our disclosure controls and procedures as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer of our general partner concluded that our disclosure controls and procedures, as of September 30, 2017, were effective.

Changes in internal control over financial reporting. There were no changes in our internal control over financial reporting that occurred during the three months ended September 30, 2017 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

The information required by this item is included under the caption "Commitments and Contingencies" in Note 14 to our unaudited condensed consolidated financial statements and is incorporated herein by reference thereto.

Item 1A. Risk Factors

See the risk factors set forth in Part I, Item 1A, of our Annual Report on Form 10-K for the year ended December 31, 2016.

Item 6. Exhibits

The information required by this Item 6 is set forth in the Index to Exhibits accompanying this quarterly report and is incorporated herein by reference.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

		BLUEKNIGHT ENERGY PARTNERS, L.P.	
		By:	Blueknight Energy Partners, G.P., L.L.C its general partner
Date:	November 1, 2017	By:	/s/ Alex G. Stallings Alex G. Stallings Chief Financial Officer and Secretary
Date:	November 1, 2017	By:	/s/ James R. Griffin James R. Griffin Chief Accounting Officer

INDEX TO EXHIBITS

Exhibit Number	Exhibit Name
3.1	Amended and Restated Certificate of Limited Partnership of the Partnership, dated November 19, 2009 but effective as of December 1, 2009 (filed as Exhibit 3.1 to the Partnership's Current Report on Form 8-K, filed November 25, 2009 (Commission File No. 001-33503), and incorporated herein by reference).
3.2	Fourth Amended and Restated Agreement of Limited Partnership of the Partnership, dated September 14, 2011 (filed as Exhibit 3.1 to the Partnership's Current Report on Form 8-K, filed September 14, 2011 (Commission File No. 001-33503), and incorporated herein by reference).
3.3	Amended and Restated Certificate of Formation of the General Partner, dated November 20, 2009 but effective as of December 1, 2009 (filed as Exhibit 3.2 to the Partnership's Current Report on Form 8-K, filed November 25, 2009 (Commission File No. 001-33503), and incorporated herein by reference).
3.4	Second Amended and Restated Limited Liability Company Agreement of the General Partner, dated December 1, 2009 (filed as Exhibit 3.2 to the Partnership's Current Report on Form 8-K, filed December 7, 2009 (Commission File No. 001-33503), and incorporated herein by reference).
31.1#	Certifications of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2#	Certifications of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1#	Certification of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C., Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. Pursuant to SEC Release 34-47551, this Exhibit is furnished to the SEC and shall not be deemed to be "filed."
101#	The following financial information from Blueknight Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended September 30, 2017, formatted in XBRL (eXtensible Business Reporting Language): (i) Document and Entity Information; (ii) Unaudited Condensed Consolidated Balance Sheets as of December 31, 2016 and September 30, 2017; (iii) Unaudited Condensed Consolidated Statements of Operations for the three and nine months ended September 30, 2016 and 2017; (iv) Unaudited Condensed Consolidated Statement of Changes in Partners' Capital for the nine months ended September 30, 2017; (v) Unaudited Condensed Consolidated Statements of Cash Flows for the nine months ended September 30, 2016 and 2017; and (vi) Notes to Unaudited Condensed Consolidated Financial Statements.

\# Furnished herewith