Blueknight Energy Partners, L.P.
Form 10-Q
August 03, 2016

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 June 30, 2016

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, or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act. (Check one):

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

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

As of July 28, 2016, there were 30,147,624 Series A Preferred Units and 37,049,876 common units outstanding.

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PART I. FINANCIAL INFORMATION

Item 1. Unaudited Condensed Financial Statements

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

	As of December 31, 2015	As of June 30, 2016
		(unaudited)
ASSETS		
Current assets:		
Cash and cash equivalents	$3,038	$3,034
Accounts receivable, net of allowance for doubtful accounts of $38 and $17 at December 31, 2015 and June 30, 2016, respectively	8,697	10,664
Receivables from related parties, net of allowance for doubtful accounts of $225 and $0 at December 31, 2015 and June 30, 2016, respectively	1,844	1,563
Prepaid insurance	1,397	2,685
Assets held for sale, net of accumulated depreciation of $1,442 at June 30, 2016	—	1,375
Other current assets	4,384	8,312
Total current assets	19,360	27,633
Property, plant and equipment, net of accumulated depreciation of $205,967 and $216,792 at December 31, 2015 and June 30, 2016, respectively	312,934	289,733
Investment in unconsolidated affiliate	19,078	19,859
Goodwill	4,387	4,746
Debt issuance costs, net	2,201	1,778
Intangibles and other assets, net	6,786	14,625
Total assets	$364,746	$358,374
LIABILITIES AND PARTNERS’ CAPITAL		
Current liabilities:		
Accounts payable	$5,236	$4,847
Accrued interest payable	191	199
Accrued property taxes payable	2,773	3,350
Unearned revenue	4,299	3,698
Unearned revenue with related parties	756	59
Accrued payroll	7,263	4,560
Other current liabilities	6,358	6,084
Total current liabilities	26,876	22,797
Unearned revenue with related parties, noncurrent	80	61
Other long-term liabilities	2,468	2,416
Interest rate swap liabilities	3,103	5,297
Long-term debt	245,000	279,000
Commitments and contingencies (Note 14)		
Partners’ capital:		
Common unitholders (33,039,818 and 33,213,513 units issued and outstanding at December 31, 2015 and June 30, 2016, respectively)	493,824	456,272
Series A Preferred Units (30,158,619 and 30,147,624 units issued and outstanding at December 31, 2015 and June 30, 2016, respectively)	204,599	204,599

General partner interest (1.8% interest with 1,127,755 general partner units outstanding at both dates)	(611,204)	(612,068)
Total Partners' capital	87,219	48,803
Total liabilities and Partners' capital	$364,746	$358,374

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

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

	Three Months ended June 30,		Six Months ended June 30,	
	2015	2016	2015	2016
	(unaudited)			
Service revenue:				
Third party revenue	$36,389	$30,854	$68,512	$61,110
Related party revenue	10,185	5,862	20,418	12,871
Product sales revenue:				
Third party revenue	—	6,709	—	10,454
Total revenue	46,574	43,425	88,930	84,435
Costs and expenses:				
Operating	33,383	27,290	65,768	55,050
Cost of product sales	—	4,089	—	7,276
General and administrative	4,667	4,834	9,644	9,579
Asset impairment expense	—	22,574	—	22,845
Total costs and expenses	38,050	58,787	75,412	94,750
Gain (loss) on sale of assets	(40)	14	264	(19)
Operating income (loss)	8,484	(15,348)	13,782	(10,334)
Other income (expense):				
Equity earnings in unconsolidated affiliate	1,283	157	1,939	781
Interest expense (net of capitalized interest of $50, $7, $73 and $41, respectively)	(1,951)	(3,697)	(6,234)	(8,567)
Income (loss) before income taxes	7,816	(18,888)	9,487	(18,120)
Provision for income taxes	106	48	198	90
Net income (loss)	$7,710	$(18,936)	$9,289	$(18,210)
Allocation of net income (loss) for calculation of earnings per unit:				
General partner interest in net income (loss)	$241	$(195)	$344	$(51)
Preferred interest in net income	$5,391	$5,389	$10,782	$10,780
Income (loss) available to limited partners	$2,078	$(24,130)	$(1,837)	$(28,939)
Basic and diluted net income (loss) per common unit	$0.06	$(0.71)	$(0.05)	$(0.85)
Weighted average common units outstanding - basic and diluted	32,915	33,206	32,905	33,191

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, 2015	$493,824	$204,599	$(611,204)	$87,219
Net income (loss)	(28,674)	10,782	(318)	(18,210)
Equity-based incentive compensation	801	—	14	815
Profits interest contribution	—	—	75	75
Distributions	(9,833)	(10,782)	(635)	(21,250)
Proceeds from sale of 30,444 common units pursuant to the Employee Unit Purchase Plan	154	—	—	154
Balance, June 30, 2016	$456,272	$204,599	$(612,068)	$48,803

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

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

	Six Months ended June 30,	
	2015	2016
	(unaudited)	
Cash flows from operating activities:		
Net income (loss)	$9,289	$(18,210)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Provision for uncollectible receivables from third parties	(200)	(17)
Provision for uncollectible receivables from related parties	—	(229)
Depreciation and amortization	13,384	14,823
Amortization of debt issuance costs	437	440
Unrealized loss related to interest rate swaps	1,029	2,194
Asset impairment charge	—	22,845
Loss (gain) on sale of assets	(264)	19
Equity-based incentive compensation	732	815
Equity earnings in unconsolidated affiliate	(1,939)	(781)
Distributions from unconsolidated affiliate	2,321	—
Gain related to investments	(267)	—
Changes in assets and liabilities		
Increase in accounts receivable	(5,336)	(1,950)
Decrease (increase) in receivables from related parties	(352)	510
Decrease in prepaid insurance	1,295	1,181
Increase in other current assets	(290)	(123)
Decrease (increase) in other assets	(1,720)	37
Increase in accounts payable	1,586	1,043
Increase (decrease) in accrued interest payable	(44)	8
Increase in accrued property taxes	440	577
Increase (decrease) in unearned revenue	1,465	(823)
Decrease in unearned revenue from related parties	(162)	(716)
Decrease in accrued payroll	(1,699)	(2,703)
Increase (decrease) in other accrued liabilities	(481)	39
Net cash provided by operating activities	19,224	18,979
Cash flows from investing activities:		
Acquisitions	(13,895)	(18,989)
Capital expenditures	(14,516)	(11,577)
Proceeds from sale of assets	864	1,233
Distributions from unconsolidated affiliate	538	—
Proceeds from sale of investments	2,346	—
Net cash used in investing activities	(24,663)	(29,333)
Cash flows from financing activities:		
Payment on insurance premium financing agreement	(1,445)	(2,612)
Debt issuance costs	—	(17)
Borrowings under credit facility	65,000	65,000
Payments under credit facility	(38,000)	(31,000)
Proceeds from equity issuance, net of offering costs	—	154
Capital contribution related to profits interest	74	75

Distributions	(20,497)	(21,250)
Net cash provided by financing activities	5,132	10,350
Net decrease in cash and cash equivalents	(307)	(4)
Cash and cash equivalents at beginning of period	2,661	3,038
Cash and cash equivalents at end of period	$2,354	$3,034
Supplemental disclosure of cash flow information:		
Increase (decrease) in accounts payable related to purchase of property, plant and equipment	$2,925	$(1,432)
Increase in accrued liabilities related to insurance premium financing agreement	$3,439	$2,469

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

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

1. ORGANIZATION AND NATURE OF BUSINESS

Blueknight Energy Partners, L.P. and subsidiaries (collectively, the “Partnership”) is a publicly traded master limited partnership with operations in twenty-four states. The Partnership provides integrated terminalling, storage, processing, 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 and storage services, (iii) crude oil pipeline services and (iv) crude oil trucking and producer field services. The Partnership’s common units and preferred units, which represent limited partnership interests in the Partnership, are listed on the NASDAQ Global Market under the symbols “BKEP” and “BKEPP,” respectively. The Partnership was formed in February 2007 as a Delaware master limited partnership initially to own, operate and develop a diversified portfolio of complementary midstream energy assets.

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 six months ended June 30, 2015 and 2016, the condensed consolidated statement of changes in partners’ capital for the six months ended June 30, 2016, the condensed consolidated statements of cash flows for the six months ended June 30, 2015 and 2016, and the condensed consolidated balance sheet as of June 30, 2016, 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 2015 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, 2015, filed with the Securities and Exchange Commission (the “SEC”) on March 9, 2016 (the “2015 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 2015 Form 10-K.

The Partnership’s investment in Advantage Pipeline, L.L.C. (“Advantage Pipeline”), over which the Partnership has significant influence but not control, is accounted for by the equity method. The Partnership does 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 will increase or decrease, as applicable, the carrying value of the Partnership’s “Investment in unconsolidated affiliate” on the unaudited condensed consolidated balance sheets. Distributions to the Partnership reduce the carrying value of its investment and are reflected in the Partnership’s unaudited condensed consolidated statements of cash flows in the line item “Distributions from unconsolidated affiliate.” Contributions will increase the carrying value of the Partnership’s investment and will be reflected in the Partnership’s unaudited condensed consolidated statements of cash flows in investing activities.

3. RESTRUCTURING CHARGES

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

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

	Three Months ended June 30, 2016	Six Months ended June 30, 2016
	(in thousands)	
Beginning Balance	$1,003	$ 1,565
Charged to expense	—	—
Cash Payments	208	770
Ending Balance	$795	$ 795

The remaining accrual relates 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 has significant influence but not control, is accounted for by the equity method. As of June 30, 2016, the Partnership's investment represents a 30% ownership interest in Advantage Pipeline.
Summarized financial information for Advantage Pipeline is set forth in the tables below for the periods indicated (in thousands).

	December 31, 2015	June 30, 2016
Balance sheets		
Current assets	$2,496	$1,812
Noncurrent assets	86,702	90,089
Total assets	$89,198	$91,901
Current liabilities	2,534	2,158
Long-term liabilities	23,194	23,263
Member's equity	63,470	66,480
Total liabilities and member's equity	$89,198	$91,901

	Three Months ended June 30,		Six Months ended June 30,	
	2015	2016	2015	2016
Income statements				
Operating revenues	$7,547	$3,370	$12,800	$8,475
Net income	$4,895	$607	$7,224	$3,011

5. PROPERTY, PLANT AND EQUIPMENT

	Estimated Useful Lives (Years)	December 31, 2015	June 30, 2016
		(dollars in thousands)	
Land	N/A	$19,680	$23,234
Land improvements	10-20	6,382	6,663
Pipelines and facilities	5-30	165,497	166,813
Storage and terminal facilities	10-35	251,051	260,705
Transportation equipment	3-10	13,728	11,981
Office property and equipment and other	3-20	28,453	29,232
Pipeline linefill and tank bottoms	N/A	3,474	3,425
Construction-in-progress	N/A	30,636	4,472
Property, plant and equipment, gross		518,901	506,525
Accumulated depreciation		(205,967)	(216,792)
Property, plant and equipment, net		$312,934	$289,733

Depreciation expense for the three months ended June 30, 2015 and 2016 was $6.7 million and $7.4 million, respectively. and depreciation expense for the six months ended June 30, 2015 and 2016 was $13.4 million and $14.3 million, respectively.

For the three and six months ended June 30, 2016, the Partnership recorded asset impairment expense of $22.6 million and $22.8 million, respectively. This is primarily due to an impairment recognized on the Knight Warrior pipeline project, a previously announced East Texas Eaglebine/Woodbine crude oil pipeline project. The Knight Warrior pipeline project is being 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, one of which is a transportation agreement with Eaglebine Crude Oil Marketing LLC, which is 50% owned by Vitol (who also owns 50% of BKEP’s general partner), have been canceled. In connection with the cancellation of the shipper commitments, the Partnership evaluated the Knight Warrior project for impairment and recognized an impairment expense of $22.6 million during the three months ended June 30, 2016.

6. DEBT

On June 28, 2013, the Partnership entered into an amended and restated credit agreement that consists of a $400.0 million revolving loan facility. On September 15, 2014, the Partnership amended its credit facility to, among other things, amend the maximum permitted consolidated total leverage ratio as discussed below and to increase the limit on material project adjustments to EBITDA (as defined in the credit agreement). On July 20, 2016, the Partnership amended its credit agreement. See Note 17 Subsequent Events for additional description of the amendment of the Partnership’s credit agreement.

As of July 28, 2016, approximately $251.0 million of revolver borrowings and $1.3 million of letters of credit were outstanding under the credit facility, leaving the Partnership with approximately $147.7 million available capacity for additional revolver borrowings and letters of credit under the credit facility, although the Partnership’s ability to borrow such funds may be limited by the financial covenants in the credit facility. The proceeds of loans made under the amended and restated credit agreement may be used for working capital and other general corporate purposes of the Partnership. All references herein to the credit agreement on or after June 28, 2013, refer to the amended and restated credit agreement, as amended on September 15, 2014.

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 $500.0 million for all revolving loan commitments under the credit agreement.

The credit agreement will mature on June 28, 2018, and all amounts outstanding under the credit agreement will become due and payable on such date. The Partnership may prepay all loans under the credit agreement at any time without premium or penalty (other than customary LIBOR breakage costs), subject to certain notice requirements. The credit agreement requires mandatory prepayments of amounts outstanding thereunder with the net proceeds of certain asset sales, 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 credit agreement does not have a floor for the alternate base rate or the eurodollar rate. 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 4.50 to 1.00; provided that:

- the maximum permitted consolidated total leverage ratio is 5.00 to 1.00 for the fiscal quarters ending March 31, 2016 through September 30, 2016, 4.75 to 1.00 for the fiscal quarter ending December 31, 2016, and 4.50 to 1.00 for each fiscal quarter thereafter;
- the Partnership may elect to increase the maximum permitted consolidated total leverage ratio to 5.50 to 1.00 for two consecutive fiscal quarters ending on or before September 30, 2016; and
- if the Partnership makes a specified acquisition (as defined in the credit agreement, but generally being an acquisition with consideration in excess of $10.0 million), the Partnership may elect to increase the maximum permitted consolidated total leverage ratio to 5.00 to 1.00 from and after the last day of the fiscal quarter immediately preceding the fiscal quarter in which such acquisition occurs to and including the last day of the second full fiscal quarter following the fiscal quarter in which such acquisition occurred.

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 after the maximum permitted consolidated total leverage ratio is 5.50 to 1.00 for the fiscal quarters ending March 31, 2016 through September 30, 2016, and 5.00 to 1.00 for each fiscal quarter thereafter.

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;
- enter into operating leases; and
- make certain amendments to the Partnership’s partnership agreement.

At June 30, 2016, the Partnership’s consolidated total leverage ratio was 4.42 to 1.00 and the consolidated interest coverage ratio was 5.66 to 1.00. The Partnership was in compliance with all covenants of its credit agreement as of June 30, 2016.

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 Blueknight Energy Partners G.P., L.L.C. (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) Vitol Holding B.V. (together with its affiliates, “Vitol”) and Charlesbank Capital Partners, LLC cease to collectively own and control 50.0% or more of the membership interests of the General Partner.

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.

The Partnership capitalized no debt issuance costs during either of the three and six months ended June 30, 2015. The Partnership capitalized less than $0.1 million of debt issuance costs during three and six months ended June 30, 2016. Debt issuance costs are being amortized over the term of the amended and restated credit agreement. Interest expense related to debt issuance cost amortization for both three months ended June 30, 2015 and 2016, was $0.2 million. Interest expense related to debt issuance cost amortization for both the six months ended June 30, 2015 and 2016 was $0.4 million.

During the three months ended June 30, 2015 and 2016, the weighted average interest rate under the Partnership’s credit agreement was 3.38% and 3.89%, respectively, resulting in interest expense of approximately $2.0 million and $2.7 million, respectively. During the six months ended June 30, 2015 and 2016, the weighted average interest rate under the Partnership’s credit agreement was 3.40% and 3.75%, respectively, resulting in interest expense of approximately $3.9 million and $5.1 million, respectively. As of June 30, 2016, borrowings under the Partnership’s amended and restated credit agreement bore interest at a weighted average interest rate of 4.03%.

During each of the three months ended June 30, 2015 and 2016, the Partnership capitalized interest of less than $0.1 million. During each of the six months ended June 30, 2015 and 2016, 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. In March 2014, the Partnership entered into two interest rate swap agreements with an aggregate notional amount of $200.0 million. The first agreement has a notional amount of $100.0 million, became effective June 28, 2014, and matures on June 28, 2018. Under the terms of the first interest rate swap agreement, the Partnership pays a fixed rate of 1.45% and receives one-month LIBOR with monthly settlement. The second agreement has a notional amount of $100.0 million, became effective January 28, 2015, and matures on January 28, 2019. Under the terms of the second interest rate swap agreement, the Partnership pays a fixed rate of 1.97% and receives one-month LIBOR with monthly settlement. During the three months ended June 30, 2015 and 2016, the Partnership recorded swap interest expense of $0.8 million and $0.6 million, respectively. During the six months ended June 30, 2015 and 2016, the Partnership recorded swap interest expense of $1.4 million and $1.3 million, respectively. The fair market value of the interest rate swaps at December 31, 2015 and June 30, 2016 is a liability of $3.1 million and $5.3 million, respectively, and is recorded in long-term interest rate swap liabilities 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.

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 June 30,		Six Months ended June 30,	
	2015	2016	2015	2016
Net income (loss)	$7,710	$(18,936)	$9,289	$(18,210)
General partner interest in net income (loss)	241	(195)	344	(51)
Preferred interest in net income	5,391	5,389	10,782	10,780
Income (loss) available to limited partners	$2,078	$(24,130)	$(1,837)	$(28,939)
Basic and diluted weighted average number of units:				
Common units	32,915	33,206	32,905	33,191
Restricted and phantom units	741	906	652	761
Basic and diluted net income (loss) per common unit	$0.06	$(0.71)	$(0.05)	$(0.85)

8. PARTNERS' CAPITAL AND DISTRIBUTIONS

On September 22, 2014, the Partnership issued and sold 9,775,000 common units for a public offering price of $7.61 per unit, resulting in proceeds of approximately $71.2 million, net of underwriters' discount and offering expenses of $3.2 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 $21.2 million, net of underwriters' discount and offering expenses of $1.2 million.

On July 18, 2016, the Board approved a distribution of $0.17875 per preferred unit, or a total distribution of $5.4 million, for the quarter ending June 30, 2016. The Partnership will pay this distribution on the preferred units on August 12, 2016, to unitholders of record as of August 2, 2016.

In addition, on July 18, 2016, the Board declared a cash distribution of $0.1450 per unit on its outstanding common units. The distribution will be paid on August 12, 2016, to unitholders of record on August 2, 2016. The distribution is for the three months ended June 30, 2016. The total distribution will be approximately $5.8 million (inclusive of $0.6

million attributable to the July 26, 2016 offering), with approximately $5.4 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

The Partnership provides crude oil gathering, transportation, terminalling and storage services to Vitol. For the three months ended June 30, 2015 and 2016, the Partnership recognized revenues of $9.9 million and $5.5 million, respectively, for services provided to Vitol. For the six months ended June 30, 2015 and 2016, the Partnership recognized revenues of $19.8 million and $12.2 million, respectively, for services provided to Vitol. As of December 31, 2015 and June 30, 2016, the Partnership had receivables from Vitol of $1.8 million and $1.4 million, net of allowance for doubtful accounts. As of

December 31, 2015 and June 30, 2016, the Partnership had unearned revenues from Vitol of $0.8 million and $0.1 million, respectively.

The Partnership also provides operating and administrative services to Advantage Pipeline. For each of the three months ended June 30, 2015 and 2016, the Partnership earned revenues of $0.3 million for services provided to Advantage Pipeline. For the six months ended June 30, 2015 and 2016, the Partnership earned revenues of $0.6 million and $0.7 million, respectively, for services provided to Advantage Pipeline. As of December 31, 2015 and June 30, 2016, the Partnership had receivables from Advantage Pipeline of $0.1 million and $0.2 million, respectively.

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 by 1,500,000 common units from 2,600,000 common units 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 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 2013	7,500	$ 8.62	$ 65
December 2014	7,500	6.43	48
December 2015	15,120	5.06	77

(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 2014	276,773	$ 9.06	$ 2,508
March 2015	266,076	7.74	2,059
March 2016	416,131	4.77	1,985

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

The unrecognized estimated compensation cost of outstanding phantom units at June 30, 2016, was $2.8 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 are equity awards under ASC 718 – Stock Compensation, and, accordingly, the fair value of the awards as of the grant date is expensed over the vesting period. These units vest ratably over five years pursuant to the Employee Phantom Unit Agreement between Mr. Hurley and the General Partner and do not include DERs. The weighted average grant date fair value for the units of $5.62 was determined based on the closing market price of the Partnership's common units on the grant date of the award, less the present value of the estimated distributions to be paid to holders of an outstanding common unit prior to the vesting of the underlying award. The value of this award grant was approximately $2.8 million on the grant date, and the unrecognized estimated compensation cost at June 30, 2016, was $0.7 million and will be expensed over the remaining vesting period.

The Partnership's equity-based incentive compensation expense for the three months ended June 30, 2015 and 2016, was $0.7 million and $0.6 million, respectively. The Partnership's equity-based incentive compensation expense for both the six months ended June 30, 2015 and 2016, was $1.2 million.

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

	Number of Units	Weighted Average Grant Date Fair Value
Nonvested at December 31, 2015	915,541	$ 7.81
Granted	416,131	4.77
Vested	203,183	8.73
Forfeited	30,571	6.82
Nonvested at June 30, 2016	1,097,918	$ 6.51

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 $0.4 million and $0.3 million, respectively, for the three months ended June 30, 2015 and 2016, for discretionary contributions under the 401(k) Plan. The Partnership recognized expense of $0.8 million and $0.6 million, respectively, for the six months ended June 30, 2015 and 2016, 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 $0.1 million and $0.2 million, respectively, for the three months ended June 30, 2015 and 2016, for discretionary profit sharing contributions under the 401(k) Plan. The Partnership recognized expense of $0.3 million and $0.4 million, respectively, for the six months ended June 30, 2015 and 2016, 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 for both the three months ended June 30, 2015 and 2016, in connection with the Unit Purchase Plan. The Partnership recognized compensation expense of less than $0.1 million for both the six months ended June 30, 2015 and 2016, 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. 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, 2015			
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	$3,103	$ —	$ 3,103	$ —
Total	$3,103	$ —	$ 3,103	$ —

	Fair Value Measurements as of June 30, 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	$5,297	$ —	$ 5,297	$ —

Total	$5,297	$ —	$ 5,297	$ —

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 June 30, 2016, 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 June 30, 2016 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 and storage 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, storage and blending services at its 45 terminalling and storage facilities located in 23 states.

CRUDE OIL TERMINALLING AND STORAGE SERVICES —The Partnership provides crude oil terminalling and storage services at its terminalling and storage facilities located in Oklahoma and Texas.

CRUDE OIL PIPELINE SERVICES —The Partnership owns and operates three pipeline systems, the Mid-Continent system, the East Texas system and the Eagle North System, that gather crude oil purchased by its customers and transports it to refiners, to common carrier pipelines for ultimate delivery to refiners or to terminalling and storage facilities owned by the Partnership and others. The Partnership also engages in marketing crude oil that is purchased at production leases and transported on its pipelines. The Partnership refers to its pipeline system located in Oklahoma and the Texas Panhandle as the Mid-Continent system. It refers to its second pipeline system, which is located in Texas, as the East Texas system. The Partnership refers to its third system, originating in Cushing, Oklahoma, and terminating in Ardmore, Oklahoma, as the Eagle North system.

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

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

	Three Months ended June 30,		Six Months ended June 30,	
	2015	2016	2015	2016
Asphalt Terminalling Services				
Service revenue				
Third party revenue	$19,016	$18,132	$33,628	$35,438
Related party revenue	253	256	405	558
Total revenue for reportable segments	19,269	18,388	34,033	35,996
Operating expense (excluding depreciation and amortization)	6,607	6,839	12,758	13,271
Operating margin (excluding depreciation and amortization)	12,662	11,549	21,275	22,725
Total assets (end of period)	$108,426	$117,096	$108,426	$117,096
Crude Oil Terminalling and Storage Services				
Service revenue				
Third party revenue	$3,643	$3,626	$6,197	$7,187
Related party revenue	2,934	2,645	6,010	5,404
Total revenue for reportable segments	6,577	6,271	12,207	12,591
Operating expense (excluding depreciation and amortization)	1,695	1,134	3,257	2,295
Operating margin (excluding depreciation and amortization)	4,882	5,137	8,950	10,296
Total assets (end of period)	$68,814	$74,072	$68,814	$74,072
Crude Oil Pipeline Services				
Service revenue				
Third party revenue	$4,238	$2,702	$8,513	$4,954
Related party revenue	2,607	985	4,990	3,305
Product sales revenue				
Third party revenue	—	6,709	—	10,454
Total revenue for reportable segments	6,845	10,396	13,503	18,713
Operating expense (excluding depreciation and amortization)	4,825	3,711	8,733	7,939
Operating expense (intersegment)	—	235	—	495
Cost of product sales	—	4,089	—	7,276
Cost of product sales (intersegment)	—	426	—	426
Operating margin (excluding depreciation and amortization)	2,020	1,935	4,770	2,577
Total assets (end of period)	$194,293	$153,706	$194,293	$153,706
Crude Oil Trucking and Producer Field Services				
Service revenue				
Third party revenue	$9,492	$6,394	$20,174	$13,531
Related party revenue	4,391	1,976	9,013	3,604
Intersegment revenue	—	235	—	495
Product sales revenue				
Intersegment revenue	—	426	—	426
Total revenue for reportable segments	13,883	9,031	29,187	18,056
Operating expense (excluding depreciation and amortization)	13,518	7,918	27,636	16,722
Operating margin (excluding depreciation and amortization)	365	1,113	1,551	1,334
Total assets (end of period)	$16,513	$13,503	$16,513	$13,503

Total operating margin (excluding depreciation and amortization)(1)	$19,929	$19,734	$36,546	$36,932

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Total Segment Revenues	$46,574	$44,086	$88,930	$85,356
Elimination of Intersegment Revenues	$—	$(661)	$—	$(921)
Consolidated Revenues	$46,574	$43,425	$88,930	$84,435

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

	Three Months ended June 30,		Six Months ended June 30,	
	2015	2016	2015	2016
Operating margin (excluding depreciation and amortization)	$19,929	$19,734	$36,546	$36,932
Depreciation and amortization	(6,738)	(7,688)	(13,384)	(14,823)
General and administrative expenses	(4,667)	(4,834)	(9,644)	(9,579)
Asset impairment expense	—	(22,574)	—	(22,845)
Gain (loss) on sale of assets	(40)	14	264	(19)
Interest expense	(1,951)	(3,697)	(6,234)	(8,567)
Equity earnings in unconsolidated affiliate	1,283	157	1,939	781
Income (loss) before income taxes	$7,816	$(18,888)	$9,487	$(18,120)

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

The Partnership has contractual obligations to perform dismantlement and removal activities in the event that some of its asphalt product and residual fuel oil terminalling and storage assets are abandoned. These obligations include varying levels of activity including completely removing the assets and returning the land to its original state. The Partnership has determined that the settlement dates related to the retirement obligations are indeterminate. The assets with indeterminate settlement dates have been in existence for many years and with regular maintenance will continue to be in service for many years to come. Also, it is not possible to predict when demands for the Partnership's terminalling and storage services will cease, and the Partnership does not believe that such demand will cease for the foreseeable future. Accordingly, the Partnership believes the date when these assets will be abandoned is indeterminate. With no reasonably determinable abandonment date, the Partnership cannot reasonably estimate the fair value of the associated asset retirement obligations. Management believes that if the Partnership's asset retirement obligations were settled in the foreseeable future the 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 distributions and none of the Partnership's income, gains, losses, deductions or credits would flow through to its unitholders. Because a tax would be imposed upon the Partnership as an entity, cash available for distribution to its unitholders would be substantially reduced. Treatment of the Partnership as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to unitholders and thus would likely result in a substantial reduction in the value of the Partnership's units.

The Partnership has entered into storage 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 June 30, 2016, are presented below (dollars in thousands):

Deferred tax assets	
Difference in bases of property, plant and equipment	$871
Deferred tax asset	871
Less: valuation allowance	871
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 June 30, 2016.

16. RECENTLY ISSUED ACCOUNTING STANDARDS

Except as discussed below and in our 2015 Annual Report on Form 10-K, there have been no new accounting pronouncements that have become effective or have been issued during the six months ended June 30, 2016 that are of significance or potential significance to us

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. In August 2015, the FASB issued Accounting Standards Update No. 2015-14, “Revenue from Contracts with Customers.” The amendment in this update deferred the effective date of ASU 2014-09 by one year to annual reporting periods beginning after December 15, 2017, including interim reporting periods within that reporting period. Earlier application is permitted only as of annual reporting periods beginning after December 15, 2016, including interim reporting periods within that reporting period. In March 2016, the FASB issued ASU 2016-08, “Revenue from Contracts with

Customers (Topic 606) Principal versus Agent Considerations." This update offers guidance on principal versus agent considerations in relation to ASU 2014-09, "Revenue from Contracts with Customers." The effective date for the amendments in this update are the same as the effective date of ASU 2014-09. In March 2016, the FASB also issued ASU 2016-10, "Revenue from Contracts with Customers (Topic 606) Identifying Performance Obligations and Licensing." This update offers guidance on identifying performance obligations and licensing in relation to ASU 2014-09, "Revenue from Contracts with Customers." The effective date for the amendments in this update are the same as the effective date of ASU 2014-09. In May 2016, the FASB issued ASU 2016-12, "Revenue from Contracts with Customers (Topic 606) Narrow-Scope Improvements and Practical Expedients." This update is issued in relation to ASU 2014-09, "Revenue from Contracts with Customers" and is intended to reduce the potential for diversity if practice at initial application and also to reduce the cost and complexity of applying Topic 606 both at transition and on an ongoing basis. The effective date for the amendments in this update are the same as the effective date of ASU 2014-09. 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.

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 is evaluating the impact of this guidance, which will be adopted beginning with the Partnership's quarterly report for the period ending March 31, 2017.

In June 2016, the FASB issued ASU 2016-13, "Financial Instruments - Credit Losses (Topic 326) Measurement of Credit Losses on Financial Instruments." This update is to provide financial statement users with more decision-useful information about the expected credit losses on financial instruments and other commitments to extend credit held by a reporting entity at each reporting date. The amendments in this Update replace the incurred loss impairment methodology in current GAAP with a
methodology that reflects expected credit losses and requires consideration of a broader range of reasonable and supportable information to inform credit loss estimates. This update is effective for financial statements issued for annual periods beginning after December 15, 2019, and interim periods within those fiscal years. The Partnership is evaluating the impact of this guidance, which will be adopted beginning with the Partnership's quarterly report for the period ending March 31, 2020.

17. SUBSEQUENT EVENTS

Ergon Transactions

Membership Interest Purchase Agreement

On July 19, 2016, the Partnership announced that Ergon, Inc. ("Ergon") has agreed to purchase 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, pursuant to a Membership Interest Purchase Agreement dated July 19, 2016 among CB-Blueknight, LLC ("CBB"), an indirect wholly-owned subsidiary of Charlesbank, Blueknight Energy Holding, Inc. ("BEHI"), an indirect wholly-owned subsidiary of Vitol, and Ergon Asphalt Holdings, LLC, a wholly owned subsidiary of Ergon.

Contribution Agreement

In addition, Ergon has agreed (i) to contribute nine asphalt terminals it currently owns plus $22.1 million in cash to the Partnership in return for total consideration of approximately $130.9 million, which consists of the issuance of 18,312,968 of the Partnership's Series A preferred units in a private placement, and (ii) to acquire an aggregate of $5.0 million of common units for cash in a private placement, pursuant to a Contribution Agreement between the Partnership, Blueknight Terminal Holding, L.L.C., and three indirect wholly-owned subsidiaries of Ergon. The asphalt terminals are located in (i) Wolcott, Kansas, (ii) Ennis, Texas, (iii) Chandler, Arizona, (iv) Mt. Pleasant, Texas, (v) Pleasanton, Texas, (vi) Birmingport, Alabama, (vii) Memphis, Tennessee, (viii) Nashville, Tennessee and (ix) Yellow

Creek, Mississippi and include approximately 2.0 million barrels of storage capacity. Upon closing of the transactions contemplated by the Contribution Agreement, the Partnership will own a network of 54 asphalt terminals in 26 states with a combined capacity of 10.2 million barrels of asphalt and residual fuel oil storage.

Preferred Unit Purchase Agreement

Pursuant to a Preferred Unit Purchase Agreement dated July 19, 2016 among the Partnership, CBB and BEHI, the Partnership has agreed to purchase 6,667,695 Series A preferred units from each of Vitol and Charlesbank in a private placement for an aggregate purchase price of approximately $95.3 million. Vitol and Charlesbank will each retain 2,488,789 Series A preferred units upon completion of these transactions.

Ergon's purchase of Blueknight GP Holding, L.L.C., Ergon's contribution of the asphalt terminals and cash to the Partnership and the Partnership's repurchase of Series A preferred units from Vitol and Charlesbank (collectively, the "Transactions") are each conditioned upon the simultaneous closing of the other transactions, and a number of other closing conditions, including expiration of the applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, and other regulatory approvals and the distribution to holders of Series A preferred units of an information statement on Schedule 14C. The Transactions are expected to close on or before September 30, 2016.

Credit Facility Amendment

On July 19, 2016, the Partnership entered into a Second Amendment to Amended and Restated Credit Agreement (the "Credit Agreement Amendment"), which amended the Amended and Restated Credit Agreement, dated as of June 28, 2013, with Wells Fargo Bank, National Association as administrative agent and the several lenders from time to time party thereto, as amended.

The Credit Agreement Amendment amends the Partnership's credit agreement to, among other things:

- permit the Transactions by amending (i) the definition of Change of Control (as defined in the Credit Agreement) to permit Ergon to purchase all of the membership interests of the Partnership's general partner and, after such purchase, require Ergon to retain at least 50% of the issued and outstanding voting equity interests of the Partnership's general partner and (ii) the negative covenant contained in the Partnership's credit agreement that restricts the Partnership from repurchasing the Partnership's outstanding partnership interests, such that the Partnership may repurchase approximately 13,335,390 of the Partnership's outstanding Series A preferred units simultaneously with the closing of the Transactions;
- amend the maximum permitted consolidated total leverage ratio such that
- prior to the date on which the Partnership issues qualified senior notes (as defined in the Partnership's credit agreement, but generally being unsecured indebtedness with no required principal payments prior to June 28, 2019) 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 "Qualified Senior Notes Date"), the maximum permitted consolidated total leverage ratio will be 5.00 to 1.00 for the fiscal quarters ending June 30, 2016 and September 30, 2016 and 4.75 to 1.00 for each fiscal quarter ending thereafter; provided, that, the maximum permitted consolidated total leverage ratio will be 5.25 to 1.00 for certain quarters based on the occurrence of a specified acquisition (as defined in the Partnership's credit agreement, but generally being an acquisition for which the aggregate consideration is $15.0 million or more, which will include the acquisition of the nine asphalt terminals from Ergon);
- from and after the Qualified Senior Notes Date, the maximum permitted consolidated total leverage ratio will be 5.00 to 1.00; provided, that, the maximum permitted consolidated total leverage ratio will be 5.50 to 1.00 for certain quarters based on the occurrence of a specified acquisition;
- require that the Partnership and its subsidiaries execute certain account control agreements;
- require that, to the extent (i) the Partnership's consolidated total leverage ratio as of the end of the prior fiscal quarter was greater than 4.75 to 1.00 and (ii) the Partnership and its subsidiaries have cash and cash equivalents (subject to certain exceptions) exceeding $20.0 million for four consecutive business days, the Partnership prepay the Partnership's outstanding obligations under the Partnership's credit agreement in the amount of such excess; and
- restrict the Partnership from borrowing funds under the Partnership's credit agreement if, after giving effect to such borrowing and the prompt use of the proceeds thereof, the Partnership and its subsidiaries would have cash and cash equivalents (subject to certain exceptions) exceeding $20.0 million.

The Partnership was in compliance with all covenants of its credit agreement as of June 30, 2016.

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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," "our," "we," "us" and similar terms refer to Blueknight Energy Partners, L.P., together with its subsidiaries, (2) our "General Partner" refers to Blueknight Energy Partners G.P., L.L.C., (3) Vitol refers to Vitol Holding B.V., its affiliates and subsidiaries (other than our General Partner and us) and (4) Charlesbank refers to Charlesbank Capital Partners, LLC, its affiliates and subsidiaries (other than our General Partner and us). 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, 2015, which was filed with the Securities and Exchange Commission (the "SEC") on March 9, 2016 (the "2015 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 2015 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 twenty-four states. We provide integrated terminalling, storage, gathering and transportation services for companies engaged in the production, distribution and marketing of crude oil and liquid asphalt cement. We manage our operations through four operating segments: (i) asphalt terminalling services, (ii) crude oil terminalling and storage services, (iii) crude oil pipeline services and (iv) crude oil trucking and producer field services.

Potential Impact of Recent 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 decreased by approximately 60%, from a peak of approximately $108 per barrel to approximately $43 per barrel in July of 2016. In addition, 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). 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 spend. As a result, we do not expect the significant decrease in the price of crude oil to significantly impact our asphalt terminalling services operating segment.

Crude Oil Terminalling and Storage Services - A contango crude oil curve tends to favor the crude oil storage business as crude oil marketers are incentivized to store crude oil during the current month and sell into 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 curve, we have been able to renew expiring contracts at average rates higher than those in place at September 30, 2014, and increase customer diversity by the addition of two new customers, as a result of which storage capacity leased by Vitol decreased from nearly two-thirds of our Cushing storage at September 30, 2014, to less than one-half beginning in the second quarter of 2015. The percentage of storage capacity leased by Vitol has remained consistent since the second quarter of 2015.

Crude Oil Pipeline Services - We do not currently expect the recent crude oil price changes to have a significant impact on our Mid-Continent pipeline system as a portion of that capacity is contracted under a long-term throughput and deficiency agreement and volumes remained consistent throughout 2015. However, in late April 2016, as a precautionary measure we suspended service on our Mid-Continent pipeline system due to a discovery of a pipeline exposure caused by recent heavy rains and the erosion of a riverbed in southern Oklahoma. There was no damage to the pipe and no loss of product. In the second quarter of 2016, we took action to mitigate the service suspension and worked with customers to divert volumes, and, in certain circumstances, transported volumes to a third-party pipeline system via truck. In addition, the term of the throughput and deficiency agreement on our Eagle North 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. This enabled us to begin to recapture diverted volumes and deliver those barrels to Cushing, Oklahoma starting in July of 2016. As a result, we are currently operating one Oklahoma mainline system, which is a combination of both the Mid-Continent and Eagle Pipeline systems instead of two separate systems. We continue to evaluate the timing of and long-term repair necessary to allow us to operate two separate Oklahoma pipeline systems as well as the overall potential financial impact. The timing, cost and overall potential financial impact of re-establishing a second Oklahoma pipeline system is dependent on the overall scope of our condensate pipeline project, which we continue to evaluate and will be dependent on customer demand and/or volume commitments.

We have experienced a decrease in revenue on our East Texas pipeline system as a result of an overall decrease in production in the area and the expiration of an incentive tariff on a section of the system. As a result of the decrease in revenues and resulting decline in market values, we recognized non-cash impairment expenses of $12.6 million and $1.4 million related to our East Texas pipeline system and a portion of our Mid-Continent pipeline system, respectively, in the fourth quarter of 2015. In addition, in West Texas a number of new pipelines have been or are expected to be put into service, which will increase the amount of takeaway capacity and competition for the same or declining volumes of crude oil and may impact margins and future equity earnings from the Advantage Pipeline, in which we have a 30% equity ownership interest.

We also evaluated the current prospects of Knight Warrior, a previously announced East Texas Eaglebine/Woodbine crude oil pipeline project, and have decided to not pursue development of the project. The Knight Warrior project is being 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, one of which is a transportation agreement with Eaglebine Crude Oil Marketing LLC, which is 50% owned by Vitol (who also owns 50% of BKEP's general partner), 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 during the three months ended June 30, 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 started decreasing. Throughout 2015, we experienced downward rate pressure in our trucking and producer field services business as producers and marketers attempted to renegotiate service rates to preserve their operating margins in the changing market. In addition, during the second half of 2015, our West Texas operating margins and transported volumes were negatively impacted by increased competition from transporters moving equipment from crude oil shale areas to West Texas, where crude oil volumes have remained relatively consistent, and by producers and marketers quickly pipe-connecting transported barrels. As a result, we decided to cease trucking barrels in West Texas and refocus our efforts on transporting barrels around our owned crude oil pipelines and storage assets in Oklahoma and Kansas. In the fourth quarter of 2015, we recorded a restructuring charge of $1.6 million associated with our exit from West Texas, in addition to a non-cash impairment expense of $0.5 million associated with a write-down of assets to their estimated net realizable value. See Note 3 to our unaudited condensed consolidated financial statements for additional detail regarding this restructuring expense.

Organic Projects vs. Acquisitions - In addition to the impacts above, we anticipate that a prolonged period of lower crude oil prices, a decrease in drilling and production volumes and increases in the cost of capital may change our bias from organic projects toward acquisitions with faster positive cash flows as opposed to organic projects that do not generate positive cash flow during their development. We plan to continue to develop projects organically, but do so considering production volumes, pricing and drilling activities in areas in which we operate.

Recent Events

Ergon Transactions

Membership Interest Purchase Agreement

On July 19, 2016, we announced that Ergon, Inc. ("Ergon") has agreed to purchase 100% of the outstanding voting stock of Blueknight GP Holding, L.L.C., which owns 100% of the capital stock of our general partner, pursuant to a Membership Interest Purchase Agreement dated July 19, 2016 among CB-Blueknight, LLC ("CBB"), an indirect wholly-owned subsidiary of Charlesbank, Blueknight Energy Holding, Inc. ("BEHI"), an indirect wholly-owned subsidiary of Vitol, and Ergon Asphalt Holdings, LLC, a wholly owned subsidiary of Ergon.

Contribution Agreement

In addition, Ergon has agreed (i) to contribute nine asphalt terminals it currently owns plus $22.1 million in cash in return for total consideration of approximately $130.9 million, which consists of the issuance of 18,312,968 of Series A preferred units in a private placement, and (ii) to acquire an aggregate of $5.0 million of common units for cash in a private placement, pursuant to a Contribution Agreement between us, Blueknight Terminal Holding, L.L.C., and three indirect wholly-owned subsidiaries of Ergon. The asphalt terminals are located in (i) Wolcott, Kansas, (ii) Ennis, Texas, (iii) Chandler, Arizona, (iv) Mt. Pleasant, Texas, (v) Pleasanton, Texas, (vi) Birmingport, Alabama, (vii) Memphis, Tennessee, (viii) Nashville, Tennessee and (ix) Yellow Creek, Mississippi and include approximately 2.0 million barrels of storage capacity. Upon closing of the transactions contemplated by the Contribution Agreement, we will own a network of 54 asphalt terminals in 26 states with a combined capacity of 10.2 million barrels of asphalt and residual fuel oil storage.

Preferred Unit Purchase Agreement

Pursuant to a Preferred Unit Purchase Agreement dated July 19, 2016 among us, CBB and BEHI, we have agreed to purchase 6,667,695 Series A preferred units from each of Vitol and Charlesbank in a private placement for an aggregate purchase price of approximately $95.3 million. Vitol and Charlesbank will each retain 2,488,789 Series A preferred units upon completion of these transactions.

Ergon's purchase of Blueknight GP Holding, L.L.C., Ergon's contribution of the asphalt terminals and cash to us and our repurchase of Series A preferred units from Vitol and Charlesbank (collectively, the "Transactions") are each conditioned upon the simultaneous closing of the other transactions, and a number of other closing conditions, including expiration of the applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, and other regulatory approvals and the distribution to holders of Series A preferred units of an information statement on Schedule 14C. The Transactions are expected to close on or before September 30, 2016.

Credit Facility Amendment

On July 19, 2016, we entered into a Second Amendment to Amended and Restated Credit Agreement (the "Credit Agreement Amendment"), which amended the Amended and Restated Credit Agreement, dated as of June 28, 2013, with Wells Fargo Bank, National Association as administrative agent and the several lenders from time to time party thereto, as amended.

The Credit Agreement Amendment amends the credit agreement to, among other things:

- permit the Transactions by amending (i) the definition of Change of Control (as defined in the Credit Agreement) to permit Ergon to purchase all of the membership interests of our general partner and, after such purchase, require Ergon to retain at least 50% of the issued and outstanding voting equity interests of our general partner and (ii) the negative covenant contained in the credit agreement that restricts us from repurchasing the Partnership's outstanding partnership interests, such that we may repurchase approximately 13,335,390 of the Partnership's outstanding Series A preferred units simultaneously with the closing of the Transactions;

- amend the maximum permitted consolidated total leverage ratio such that

- prior to the date on which we issue qualified senior notes (as defined in the credit agreement, but generally being unsecured indebtedness with no required principal payments prior to June 28, 2019) 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 "Qualified Senior Notes Date"), the maximum permitted consolidated total leverage ratio will be 5.00 to 1.00 for the fiscal quarters ending June 30, 2016 and September 30, 2016 and 4.75 to 1.00 for each fiscal quarter ending thereafter; 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, which will include the acquisition of the nine asphalt terminals from Ergon);
- from and after the Qualified Senior Notes Date, the maximum permitted consolidated total leverage ratio will be 5.00 to 1.00; provided, that, the maximum permitted consolidated total leverage ratio will be 5.50 to 1.00 for certain quarters based on the occurrence of a specified acquisition;
- require that we and our subsidiaries execute certain account control agreements;
- require that, to the extent (i) our consolidated total leverage ratio as of the end of the prior fiscal quarter was greater than 4.75 to 1.00 and (ii) we and our subsidiaries have cash and cash equivalents (subject to certain exceptions) exceeding $20.0 million for four consecutive business days, we prepay the outstanding obligations under the credit agreement in the amount of such excess; and
- restrict us from borrowing funds under the credit agreement if, after giving effect to such borrowing and the prompt use of the proceeds thereof, we and our subsidiaries would have cash and cash equivalents (subject to certain exceptions) exceeding $20.0 million.

We were in compliance with all covenants of its credit agreement as of June 30, 2016.

Common Stock Issuance

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 $21.2 million, net of underwriters' discount and offering expenses of $1.2 million.

Our Revenues

Our revenues consist of (i) terminalling and storage revenues, (ii) gathering, transportation and producer field services revenues, (iii) product sales revenues and (iv) fuel surcharge revenues. For the three months ended June 30, 2016, we derived approximately $5.5 million and $0.3 million and during the six months ended June 30, 2016, we derived approximately $12.2 million and $0.7 million of our revenues from services we provided to Vitol and Advantage Pipeline L.L.C. ("Advantage Pipeline"), respectively, with the remainder of our services being provided to third parties.

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

We have leases and storage agreements with third party customers for all of our 45 asphalt facilities. The majority of the leases and storage agreements related to these facilities have terms that expire between the end of 2016 and the end of 2018. We operate the asphalt facilities pursuant to the storage agreements, while our contract counterparties operate the asphalt facilities that are subject to the lease agreements.

As of July 28, 2016, we had approximately 5.8 million barrels of crude oil storage under service contracts with remaining terms ranging from 1 month to 15 months, including 2.2 million barrels of crude oil storage contracts that expire in 2016. Storage contracts with Vitol represent 2.4 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 2016; 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 and storage facilities owned by us and others. Revenue for the gathering and transportation of crude oil is recognized when the service is performed and is based upon regulated and non-regulated tariff rates and the related transport volumes. Producer field services revenue consists of a number of services ranging from gathering condensates from natural gas producers to hauling produced water to disposal wells. Revenue for producer field services is recognized when the service is performed. We earn gathering and transportation revenues in two of our segments: (i) crude oil pipeline services and (ii) crude oil trucking and producer field services.

During the three months ended June 30, 2016, we transported approximately 39,000 barrels per day on our pipelines, which is a decrease of 29% compared to the three months ended June 30, 2015. During the six months ended June 30, 2016 we transported approximately 45,000 barrels per day on our pipelines, which is a decrease of 8% compared to the six months ended June 30, 2015. Vitol accounted for 15% and 30% of volumes transported in our pipelines in the three months ended June 30, 2016 and 2015, respectively. Vitol accounted for 24% and 33% of volumes transported in our pipelines in the six months ended June 30, 2016 and 2015, respectively.

For the three months ended June 30, 2016, we transported approximately 28,000 barrels per day on our crude oil transport trucks, a decrease of 49% as compared to the three months ended June 30, 2015. Vitol accounted for approximately 29% and 45% of volumes transported by our crude oil transport trucks in the three months ended June 30, 2016 and 2015, respectively. For the six months ended June 30, 2016, we transported approximately 30,000 barrels per day on our crude oil transport trucks, a decrease of 47% as compared to the six months ended June 30, 2015. Vitol accounted for approximately 30% and 44% of volumes transported by our crude oil transport trucks in the six months ended June 30, 2016 and 2015, respectively.

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

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

Our Expenses

Operating expenses decreased by 16% in 2016 as compared to 2015. This is primarily a result of a decrease in compensation expense and fuel costs related to the restructuring of our trucking and field services operating segment initiated in the fourth quarter of 2015. General and administrative expenses also decreased by 1% in 2016 as compared to 2015. Our interest expense increased by 37% in 2016 as compared to 2015. See Interest expense within our results of operations discussion for additional detail regarding the factors that contributed to the increase in interest expense in 2016.

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 June 30, 2016.

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 July 18, 2016, the Board approved a distribution of $0.17875 per preferred unit, or a total distribution of $5.4 million, for the quarter ending June 30, 2016. We will pay this distribution on the preferred units on August 12, 2016, to unitholders of record as of August 2, 2016.

In addition, on July 18, 2016, the Board approved a cash distribution of $0.1450 per unit on our outstanding common units. The distribution will be paid on August 12, 2016, to unitholders of record on August 2, 2016. The distribution is for the three months ended June 30, 2016. The total distribution to be paid is approximately $5.8 million, inclusive of $0.6 million related to the 3.8 million common units we issued in July 2016, with approximately $5.4 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 operating margin, excluding depreciation and amortization.

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

The table below summarizes our financial results for the three and six months ended June 30, 2015 and 2016, reconciled to the most directly comparable GAAP measure:

Operating Results	Three Months ended June 30,		Six Months ended June 30,		Favorable/(Unfavorable) Three Months		Six Months	
(in thousands)	2015	2016	2015	2016	$	%	$	%
Operating Margin, excluding depreciation and amortization:								
Asphalt terminalling services operating margin	$12,662	$11,549	$21,275	$22,725	(1,113)	(9)%	1,450	7 %
Crude oil terminalling and storage operating margin	4,882	5,137	8,950	10,296	255	5 %	1,346	15 %
Crude oil pipeline services operating margin	2,020	1,935	4,770	2,577	(85)	(4)%	(2,193)	(46)%
Crude oil trucking and producer field services operating margin	365	1,113	1,551	1,334	748	205 %	(217)	(14)%
Total operating margin, excluding depreciation and amortization	19,929	19,734	36,546	36,932	(195)	(1)%	386	1 %
Depreciation and amortization	(6,738)	(7,688)	(13,384)	(14,823)	(950)	(14)%	(1,439)	(11)%
General and administrative expense	(4,667)	(4,834)	(9,644)	(9,579)	(167)	(4)%	65	1 %
Asset impairment expense	—	(22,574)	—	(22,845)	(22,574)	N/A	(22,845)	N/A
Gain (loss) on sale of assets	(40)	14	264	(19)	54	(135)%	(283)	(107)%
Operating income (loss)	8,484	(15,348)	13,782	(10,334)	(23,832)	(281)%	(24,116)	(175)%
Other income (expense):								
Equity earnings in unconsolidated entity	1,283	157	1,939	781	(1,126)	(88)%	(1,158)	(60)%
Interest expense	(1,951)	(3,697)	(6,234)	(8,567)	(1,746)	(89)%	(2,333)	(37)%
Income tax expense	(106)	(48)	(198)	(90)	58	55 %	108	55 %
Net income (loss)	$7,710	$(18,936)	$9,289	$(18,210)	(26,646)	(346)%	(27,499)	(296)%

For the three months ended June 30, 2016, operating margin, excluding depreciation and amortization, increased in our crude oil terminalling and storage services and crude oil trucking and producer field services. Crude oil terminalling and storage services margin increased as a result of increased rates under new contracts. Crude oil trucking and producer field services margin increased primarily due to a sale of crude oil and lower operating expenses. These increases were offset by lower operating margins in our asphalt terminalling services and crude oil pipeline services segments. Asphalt terminalling services margin decreased due to contract renegotiation fees, which were partially offset by increased revenues on the three asphalt terminals acquired since May 2015. Crude oil pipeline services margin decreased due to suspended service on our Mid-Continent pipeline system beginning in April 2016 due to a discovery of a pipeline exposure caused by recent heavy rains and erosion of a river in southern Oklahoma.

For the six months ended June 30, 2016, operating margin, excluding depreciation and amortization, increased in our asphalt and crude oil terminalling and storage services segments as a result of acquisitions of three asphalt terminals, annual contract escalations, and new crude oil storage and terminalling contracts. These increases were offset by lower operating margins in our crude oil pipeline services and crude oil trucking and producer field services segments. The decrease in crude oil pipeline services margin resulted from the expiration of an increased tariff that was being charged from June 2014 through May 2015 on certain barrels transported on our East Texas pipeline system under a throughput and deficiency agreement. The tariff returned to a lower rate in June of 2015, which decreased the service revenues generated on the East Texas pipeline system by $4.7 million when comparing the six months ended June 30, 2016 to the same period in 2015. This was partially offset by $1.6 million in sales of crude oil arising from product loss allowances in the six months ended June 30, 2016. 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 storage, terminalling and throughput services for asphalt product and residual fuel oil. Revenue is generated through short- and long-term storage contracts.

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

Operating results	Three Months ended June 30,		Six Months ended June 30,		Favorable/(Unfavorable) Three Months		Six Months	
(in thousands)	2015	2016	2015	2016	$	%	$	%
Service Revenue:								
Third Party Revenue	$19,016	$18,132	$33,628	$35,438	(884)	(5)%	1,810	5 %
Related Party Revenue	253	256	405	558	3	1 %	153	38 %
Total Revenue	19,269	18,388	34,033	35,996	(881)	(5)%	1,963	6 %
Operating Expense (excluding depreciation and amortization)	6,607	6,839	12,758	13,271	(232)	(4)%	(513)	(4)%
Operating Margin (excluding depreciation and amortization)	$12,662	$11,549	$21,275	$22,725	(1,113)	(9)%	1,450	7 %

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

- Third party revenues decreased for the three months ended June 30, 2016, as compared to the three months ended June 30, 2015, primarily due to contract renegotiation fees that increased revenues by $2.3 million for 2015 as compared to 2016. This was partially offset by additional revenues on two asphalt terminalling facilities acquired in February 2016. Third party revenues increased for the six months ended June 30, 2016, as compared to the six months ended June 30, 2015, as a result of the acquisition of one asphalt terminalling facility in May 2015 and two asphalt terminalling facilities in February 2016 as well as annual contract fee escalations, which were partially offset by the contract renegotiation fees noted above.

- Related party revenues are consistent for the three months ended June 30, 2016 and 2015. The variance in related party revenues for the six months ended June 30, 2016, compared to the same period in the prior year is primarily due to an additional storage tank being utilized by Vitol beginning in the the second quarter of 2015.

- Operating expenses increased for the three and six months ended June 30, 2016, as compared to the three and six months ended June 30, 2015, due primarily to the two asphalt terminalling facilities acquired in February 2016. This was partially offset by decreased maintenance and repair expenses due to the timing of maintenance projects.

Crude oil terminalling and storage services segment

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

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

Operating results	Three Months ended June 30,		Six Months ended June 30,		Favorable/(Unfavorable) Three Months		Six Months	
(in thousands)	2015	2016	2015	2016	$	%	$	%
Service Revenue:								
Third Party Revenue	$3,643	$3,626	$6,197	$7,187	(17)	— %	990	16 %
Related Party Revenue	2,934	2,645	6,010	5,404	(289)	(10)%	(606)	(10)%
Total Revenue	6,577	6,271	12,207	12,591	(306)	(5)%	384	3 %
Operating Expense (excluding depreciation and amortization)	1,695	1,134	3,257	2,295	561	33 %	962	30 %
Operating Margin (excluding depreciation and amortization)	$4,882	$5,137	$8,950	$10,296	255	5 %	1,346	15 %
Average crude oil stored per month at our Cushing terminal (in thousands of barrels)	5,977	5,816	5,167	5,628	(161)	(3)%	461	9 %
Average crude oil delivered to our Cushing terminal (in thousands of barrels per day)	109	72	117	44	(37)	(34)%	(73)	(62)%

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

- Third party revenues increased for the six months ended June 30, 2016 compared to the same period in 2015 in connection with storage contract renewals. As contracts were expiring early in 2014, the rates at which we recontracted storage at the Cushing Interchange were impacted by a backwardated market for West Texas Intermediate crude which led to a decrease in average rates for the comparative three month periods. However, in the fourth quarter of 2014, the market for West Texas Intermediate crude oil returned to contango in which future prices are higher than current prices. This has increased demand for storage services at the Cushing Interchange, resulting in an upward trend in storage rates. Due to the timing of the expiration of historical contracts and the execution of new storage contracts, the overall impact of the increase in storage rates began in the second quarter of 2015, and, as a result, revenues for the three months ended June 30, 2016 are consistent with the same period in 2015. As we negotiated new storage service contracts, we have been able to increase customer diversity by the addition of two new customers, as a result of which storage capacity leased by Vitol decreased from nearly two-thirds of our Cushing storage at September 30, 2014, to less than one-half beginning in the second quarter of 2015, resulting in an increase in third party revenue. The percentage of storage capacity leased by Vitol has remained consistent since the second quarter of 2015.

- Related party revenues decreased for both periods due to the cancellation of the Operating and Maintenance agreement related to Vitol's crude oil terminal located in Midland, Texas in the third quarter of 2015.

- As of July 28, 2016, we had approximately 5.8 million barrels of crude oil storage under service contracts with remaining terms of up to 15 months, including 2.2 million barrels of crude oil storage contracts that expire in 2016.

Storage contracts with Vitol represent 2.4 million barrels of crude oil storage capacity under contract.

- Operating expenses for the three and six months ended June 30, 2016, decreased as compared to the three and six months ended June 30, 2015, primarily as a result of decreases in utilities expense, as well as a decrease in compensation expense due to our no longer operating the Vitol Midland terminal.

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 June 30,		Six Months ended June 30,		Favorable/(Unfavorable)			
					Three Months		Six Months	
(in thousands)	2015	2016	2015	2016	$	%	$	%
Service revenue:								
Third Party Revenue	$4,238	$2,702	$8,513	$4,954	(1,536)	(36)%	(3,559)	(42)%
Related Party Revenue	2,607	985	4,990	3,305	(1,622)	(62)%	(1,685)	(34)%
Product sales revenue:								
Third Party Revenue	—	6,709	—	10,454	6,709	N/A	10,454	N/A
Total Revenue	6,845	10,396	13,503	18,713	3,551	52 %	5,210	39 %
Operating Expense (excluding depreciation and amortization)	4,825	3,711	8,733	7,939	1,114	23 %	794	9 %
Operating Expense (intersegment)	—	235	—	495	(235)	N/A	(495)	N/A
Cost of Product Sales	—	4,089	—	7,276	(4,089)	N/A	(7,276)	N/A
Cost of Product Sales (intersegment)	—	426	—	426	(426)	N/A	(426)	N/A
Operating Margin (excluding depreciation and amortization)	$2,020	$1,935	$4,770	$2,577	(85)	(4)%	(2,193)	(46)%
Average throughput volume (in thousands of barrels per day)								
Mid-Continent	23	13	22	19	(10)	(43)%	(3)	(14)%
Eagle North	15	15	10	15	—	— %	5	50 %
East Texas	17	11	17	11	(6)	(35)%	(6)	(35)%

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

- Service revenues decreased for the three and six months ended June 30, 2016, compared to the same period in 2015 due to the expiration of an increased tariff that was being charged from June 2014 through May 2015 on certain barrels transported on our East Texas pipeline system under a throughput and deficiency agreement. The tariff returned to a lower rate in June of 2015, which decreased the service revenues generated on the East Texas pipeline system by $2.2 million and $4.7 million when comparing the three and six months ended June 30, 2016, respectively, to the same periods in 2015.

- In addition, in late April 2016, as a precautionary measure we suspended service on our Mid-Continent pipeline system due to a discovery of a pipeline exposure caused by recent heavy rains and the erosion of a riverbed in southern Oklahoma. There was no damage to the pipe and no loss of product. In the second quarter of 2016, we took action to mitigate the service suspension and worked with customers to divert volumes, and, in certain circumstances, transported volumes to a third-party pipeline system via truck. In addition, the term of the throughput and deficiency agreement on our Eagle North 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. This enabled us to recapture diverted volumes and deliver those barrels to Cushing, Oklahoma. As a result, we are currently operating one Oklahoma mainline system, which is a combination of both the Mid-Continent and Eagle Pipeline systems instead of two separate systems. We continue to evaluate the timing of and long-term repair necessary to allow us to operate two separate Oklahoma pipeline systems as well as the overall potential financial impact. The timing, cost and overall potential financial impact of re-establishing a second

Oklahoma pipeline system is dependent on the overall scope of our condensate pipeline project, which we continue to evaluate and will be dependent on customer demand and/or volume commitments.

- In the first quarter of 2015, the refinery served by the Eagle North pipeline was undergoing maintenance, which temporarily decreased volumes transported on our pipeline.

- Product sales revenues increased for the three and six months ended June 30, 2016, compared to the same period in 2015 due to our acquisition of the Red River pipeline in November 2015. In conjunction with our acquisition of the Red River pipeline, we began marketing crude oil that we purchase at production leases. Revenue from this activity is reflected in product sales revenue. In addition to the marketing revenue, we also had $1.6 million in sales of crude oil arising from product loss allowances in the three and six months ended June 30, 2016. There were no such sales of crude oil arising from product loss allowances in the three and six months ended June 30, 2015.

- Cost of product sales incurred for the three and six months ended June 30, 2016, represent the cost of the marketed crude oil barrels transported on the Red River pipeline that was acquired in November 2015.

- Operating expenses have decreased primarily as a result of decreases in maintenance and repair and compensation expenses.

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 June 30,		Six Months ended June 30,		Favorable/(Unfavorable)			
					Three Months		Six Months	
(in thousands)	2015	2016	2015	2016	$	%	$	%
Service revenue:								
Third Party Revenue	$9,492	$6,394	$20,174	$13,531	(3,098)	(33)%	(6,643)	(33)%
Related Party Revenue	4,391	1,976	9,013	3,604	(2,415)	(55)%	(5,409)	(60)%
Intersegment Revenue	—	235	—	495	235	N/A	495	N/A
Product sales revenue:								
Intersegment Revenue	—	426	—	426	426	N/A	426	N/A
Total Revenue	13,883	9,031	29,187	18,056	(4,852)	(35)%	(11,131)	(38)%
Operating Expense (excluding depreciation and amortization)	13,518	7,918	27,636	16,722	5,600	41 %	10,914	39 %
Operating Margin (excluding depreciation and amortization)	$365	$1,113	$1,551	$1,334	748	205 %	(217)	(14)%
Average volume (in thousands of barrels per day)	55	28	57	30	(27)	(49)%	(27)	(47)%

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

-

Operating margin (excluding depreciation and amortization) increased for the three months ended June 30, 2016, compared to the three months ended June 30, 2015 due primarily to intersegment revenues earned from the sale of crude oil to our crude oil pipeline services segment.

- Operating margin (excluding depreciation and amortization) decreased for the six months ended June 30, 2016, compared to the six months ended June 30, 2015, primarily due to continued pressure on trucking and producer field service rates due to the decline in crude oil prices and a decrease in transported volumes.

Other Income and Expenses

Depreciation and amortization. Depreciation and amortization increased by $1.0 million to $7.7 million for the three months ended June 30, 2016, compared to $6.7 million for the three months ended June 30, 2015. Depreciation and amortization increased by $1.4 million to $14.8 million for the six months ended June 30, 2016, compared to $13.4 million for the six months ended June 30, 2015. This increase is primarily due to depreciation of the asphalt terminal acquired in the second quarter of 2015 as well as the two asphalt terminals acquired in the first quarter of 2016.

General and administrative expenses. General and administrative expenses increased to $4.8 million for the three months ended June 30, 2016, compared to $4.7 million for the three months ended June 30, 2015. This increase is primarily due to $0.5 million of transaction fees related to the Ergon transaction offset by decreases in compensation expense and insurance premiums due to decreased headcount. General and administrative expenses was consistent at $9.6 million for the six months ended June 30, 2016, compared to the six months ended June 30, 2015. A decrease in compensation expense related to reduced headcount and a reduction in insurance premiums wasoffset by approximately $0.5 million of transaction fees related to the Ergon Transactions. We expect incremental expenses of approximately $1.0 million to $1.5 million in the third quarter of 2016 in relation to the Ergon Transaction.

Asset impairment expense. We evaluated the current prospects of Knight Warrior, a previously announced East Texas Eaglebine/Woodbine crude oil pipeline project, and have decided to not pursue development of the project. The Knight Warrior project is being 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, one of which is a transportation agreement with Eaglebine Crude Oil Marketing LLC, which is 50% owned by Vitol (who also owns 50% of BKEP's general partner), 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 during the three months ended June 30, 2016.

Gain (loss) on sale of assets. Gains (losses) in both periods were primarily comprised of sales of surplus, used property and equipment.

Equity earnings in unconsolidated affiliate. The equity earnings are attributed to our investment in Advantage Pipeline. Earnings have decreased in the three and six months ended June 30, 2016, as compared to the three and six months ended June 30, 2015, as a result of decreased volumes transported by Advantage Pipeline as well as a decreased tariff that became effective in March 2016.

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 June 30, 2016 increased by $1.7 million compared to the three months ended June 30, 2015. During the three months ended June 30, 2016, we recorded unrealized losses of $0.3 million due to the change in the fair value of interest rate swaps compared to unrealized gains of $0.8 million during the three months ended June 30, 2015. We also incurred interest expense in connection with settlement payments under our interest rate swap agreements of $0.6 million during the three months ended June 30, 2016. During the three months ended June 30, 2015, we incurred interest expense in connection with settlement payments under our interest rate swap agreements of $0.8 million. In addition, interest on our credit facility increased by $0.7 million due to increases in our average debt outstanding and increases in the weighted average interest rate under our credit agreement.

Total interest expense for the six months ended June 30, 2016 increased by $2.3 million compared to the six months ended June 30, 2015. During the six months ended June 30, 2016, we recorded unrealized losses of $2.2 million due to the change in fair value of interest rate swaps compared to unrealized losses of $1.0 million during the six months ended June 30, 2015. We also incurred interest expense in connection with settlement payments under our interest rate swap agreements of $1.3 million during the six months ended June 30, 2016. During the six months ended June 30, 2015, we incurred interest expense in connection with settlement payments under our interest rate swap agreements of $1.4 million. In addition, interest on our credit facility increased by $1.3 million due to increases in our average debt outstanding and increases in the weighted average interest rate under our credit agreement.

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 six months ended June 30, 2015 and 2016:

	Six Months ended June 30,	
	2015	2016
	(in millions)	
Net cash provided by operating activities	$19.2	$19.0
Net cash used in investing activities	(24.7)	(29.3)
Net cash provided by financing activities	5.1	10.4

Operating Activities. Net cash provided by operating activities was $19.0 million for the six months ended June 30, 2016, as compared to $19.2 million for the six months ended June 30, 2015. The decrease in cash provided by operating activities is primarily the results of changes in working capital.

Investing Activities. Net cash used in investing activities was $29.3 million for the six months ended June 30, 2016, as compared to $24.7 million for the six months ended June 30, 2015. We acquired two asphalt terminalling facilities for $19.0 million during the six months ended June 30, 2016. Capital expenditures for the six months ended June 30, 2016 and 2015 included gross maintenance capital expenditures of $7.3 million and $3.1 million, respectively, and expansion capital expenditures of $4.3 million and $11.4 million, respectively. The six months ended June 30, 2015 also included $0.5 million in distributions received from Advantage Pipeline classified as a return of capital and $2.3 million in proceeds related to the sale of 30,393 Class A Common Units of SemCorp we received in connection with the settlement of two unsecured claims we filed in connection with SemCorp's predecessor's bankruptcy filing in 2008.

Financing Activities. Net cash provided by financing activities was $10.4 million for the six months ended June 30, 2016, as compared to $5.1 million for the six months ended June 30, 2015. Cash provided by financing activities for the six months ended June 30, 2016 was due to net borrowings on long-term debt of $34.0 million partially offset by $21.3 million in distributions to our unitholders. Net cash provided by financing activities for the six months ended June 30, 2015 consisted primarily of net borrowings on long-term debt of $27.0 million partially offset by $20.5 million in distributions to our unitholders.

Our Liquidity and Capital Resources

Cash flows from operations and our credit facility are our primary sources of liquidity. At June 30, 2016, we had a working capital surplus of $4.8 million. At June 30, 2016, we had approximately $119.7 million of availability under our credit facility, although our ability to borrow such funds may be limited by the financial covenants in our credit facility. As of June 30, 2016, we could borrow up to $316.5 million, or an additional $26.2 million, under our credit facility within our covenant restrictions. As of July 28, 2016, we have aggregate unused commitments under our revolving credit facility of approximately $147.7 million and cash on hand of approximately $23.0 million. The credit agreement will mature on June 28, 2018, and all amounts will become due and payable on such date. See the caption "Debt" in Note 6 and "Credit Facility Amendment" in Note 17 to our unaudited condensed consolidated financial statements for further details.

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 $0.3 million, totaled $4.0 million in the six months ended June 30, 2016 compared to $11.4 million in the six months ended June 30, 2015. We currently expect our expansion capital expenditures for organic growth projects to be approximately $8.0 million to $9.0 million for all of 2016. Maintenance capital expenditures totaled $5.6 million, net of reimbursable expenditures of $1.7 million, in the six months ended June 30, 2016 compared to $2.9 million in the six months ended June 30, 2015. We currently expect maintenance capital expenditures to be approximately $7.0 million to $8.0 million, net of reimbursable expenditures, for all of 2016.

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.

Contractual Obligations. A summary of our contractual cash obligations over the next several years as of June 30, 2016, is as follows:

Contractual Obligations	Payments Due by Period				
	Total	Less than 1 year	1-3 years	4-5 years	More than 5 years
	(in millions)				
Debt obligations[1]	$299.8	$10.4	$289.4	$ —	$ —
Operating lease obligations	18.8	5.6	8.3	3.3	1.6

(1) Represents required future principal repayments of borrowings of $279.0 million and variable rate interest payments of $20.8 million. At June 30, 2016, our borrowings had an interest rate of approximately 4.03%. This interest rate was used to calculate future interest payments. All amounts outstanding under our credit agreement mature in June 2018.

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 July 28, 2016, we had $251.0 million outstanding under our credit facility that was subject to a variable interest rate. Borrowings under our credit agreement bear interest, at our option, at either 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%) plus an applicable margin. Interest rate swap agreements are used to manage a portion of the exposure related to changing interest rates by converting floating-rate debt to fixed-rate debt. In March 2014, we entered into two interest rate swap agreements with an aggregate notional value of $200.0 million. The first agreement became effective June 28, 2014, and matures on June 28, 2018. Under the terms of the first interest rate swap agreement, we pay a fixed rate of 1.45% and receive one-month LIBOR with monthly settlement. The second agreement became effective January 28, 2015, and matures on January 28, 2019. Under the terms of the second interest rate swap agreement, we pay a fixed rate of 1.97% and receive one-month LIBOR with monthly settlement. The fair market value of the interest rate swaps at June 30, 2016 is a liability of $5.3 million and is recorded in long-term interest rate swap liabilities 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 six months ended June 30, 2016, the weighted average interest rate under our credit agreement was 3.75%.

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 June 30, 2016, 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 annual interest expense of approximately $0.8 million and decreased annual interest expense of $0.4 million, respectively.

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 June 30, 2016, 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 June 30, 2016 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, 2015, together with the additional risk factors set forth below.

The Transactions may not be completed, and even if the Transactions are completed, we may fail to realize the benefits anticipated as a result of the Transactions.

The Transactions are expected to close on or before September 30, 2016, subject to a number of closing conditions, including clearance under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended. If these conditions are not satisfied or waived, the Transactions will not be consummated. There can be no assurances that the Transactions will be consummated or that the expected benefits of such acquisition will be realized. The closing of this offering is not conditioned on, nor is it a condition to, the consummation of the Transactions. If the Transactions are delayed, not consummated or consummated in a manner different than described herein, the price of our common units may decline. In addition, if the Transactions are not consummated, our management will have broad discretion in the application of the net proceeds of this offering. Accordingly, if you decide to purchase common units in this offering, you should be willing to do so whether or not we complete the Transactions.

If we are able to consummate the Transactions, such consummation would involve potential risks, including, without limitation, difficulties in integrating the acquired business, inefficiencies and unexpected costs and liabilities. If we consummate the Transactions and if these risks or other expected costs and liabilities were to materialize, any desired benefits of the Transactions may not be fully realized, if at all, and our future financial performance and results of operations could be negatively impacted.

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

Upon consummation of the Transactions, Ergon will indirectly own our general partner. Neither our partnership agreement nor any other agreement with Ergon prohibits Ergon from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, Ergon may acquire, construct or dispose of additional midstream or other assets in the future, without any obligation to offer us the opportunity to purchase or construct any of those assets. Ergon is privately owned company with a presence in over 12 countries worldwide, and is one of the largest asphalt emulsion marketers in the United States. Ergon has significantly greater resources and experience than we have, which factors may make it more difficult for us to compete with Ergon with respect to commercial activities as well as for acquisition candidates. As a result, competition from Ergon could adversely impact our results of operations and cash available for distribution.

Item 5. Other Information

Iran Threat Reduction and Syria Human Rights Act Disclosure

Pursuant to Section 219 of the Iran Threat Reduction and Syria Human Rights Act of 2012, which amended the Securities Exchange Act of 1934, an issuer is required to disclose in its annual or quarterly reports, as applicable, whether, during the reporting period, it or any of its affiliates knowingly engaged in certain activities, transactions or dealings relating to Iran or with individuals or entities designated pursuant to certain Executive Orders. Disclosure is generally required even where the activities, transactions or dealings were conducted in compliance with applicable laws and regulations.

The Partnership's affiliates include members of the Vitol Group of companies (Vitol). Vitol is one of the world's largest traders of oil and oil products. Following the relaxation of Iran related sanctions on January 16, 2016 an affiliate of the Partnership, Vitol Bahrain (VBA), has undertaken transactions with three Iranian state controlled companies namely the National Iranian Oil Company (NIOC), the Persian Gulf Petrochemical Industry Trading Company (PGPI) and the Kharg Petrochemical Company (KPC). During the period from April 1, 2016 to June 30, 2016, VBA bought fuel oil and naphta from NIOC for a total cost of Emirati Dirham (AED) 739,928,844.63. During the same period, VBA also bought naphthas from (1) PGPI for a cost of AED 118,987,617.71 and (2) KPC for a cost of AED 39,396,444.55. In addition, during the same period, VBA sold gasoline to NIOC for a cost of AED 112,614,750.06. VBA does not calculate net profits on a per-customer transactional basis; however, Vitol estimates that the net profits attributable to the disclosed activity would not exceed 0.5% of Vitol's annual profit. VBA anticipates that it will continue to do business with NIOC, PGPI and KPC provided that such activity continues to be permitted by applicable sanctions regimes.

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:	August 3, 2016	By:	/s/ Alex G. Stallings Alex G. Stallings Chief Financial Officer and Secretary
Date:	August 3, 2016	By:	/s/ James R. Griffin James R. Griffin Chief Accounting Officer

INDEX TO EXHIBITS

Exhibit Number	Exhibit Name
2.1	Contribution Agreement dated July 19, 2016 among Blueknight Energy Partners, L.P., Blueknight Terminal Holding, L.L.C., Ergon Asphalt & Emulsions, Inc., Ergon Terminaling, Inc. and Ergon Asphalt Holdings, LLC (filed as Exhibit 2.1 to the Partnership's Current Report on Form 8-K, filed July 20, 2016, and incorporated herein by reference).
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, and incorporated herein by reference).
3.2	Fourth Amended and Restated Agreement of Limited Partnership of the Partnership, dated September 14, 2011 (filed as Exhibit 3.1 to the Partnership's Current Report on Form 8-K, filed September 14, 2011, and incorporated herein by reference).
3.3	Amended and Restated Certificate of Formation of the General Partner, dated November 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, and incorporated herein by reference).
3.4	Second Amended and Restated Limited Liability Company Agreement of the General Partner, dated December 1, 2009 (filed as Exhibit 3.2 to the Partnership's Current Report on Form 8-K, filed December 7, 2009, and incorporated herein by reference).
10.1	Preferred Unit Repurchase Agreement dated July 19, 2016 among Blueknight Energy Partners, L.P., CB-Blueknight, LLC and Blueknight Energy Holding, Inc. (filed as Exhibit 10.1 to the Partnership's Current Report on Form 8-K, filed July 20, 2016, and incorporated herein by reference).
10.2	Second Amendment to Amended and Restated Credit Agreement dated July 19, 2016 among Blueknight Energy Partners, L.P., Wells Fargo Bank, National Association as Administrative Agent and the several lenders from time to time thereto (filed as Exhibit 10.2 to the Partnership's Current Report on Form 8-K, filed July 20, 2016, 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 June 30, 2016, formatted in XBRL (eXtensible Business Reporting Language): (i) Document and Entity Information; (ii) Unaudited Condensed Consolidated Balance Sheets as of December 31, 2015 and June 30, 2016; (iii) Unaudited Condensed Consolidated Statements of Operations for the three and six months ended June 30, 2015 and 2016; (iv) Unaudited Condensed Consolidated Statement of Changes in Partners' Capital for the six months ended June 30, 2016; (v) Unaudited Condensed Consolidated Statements of Cash Flows for the six months ended June 30, 2015 and 2016; and (vi) Notes to Unaudited Condensed Consolidated Financial Statements.

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* Filed herewith.

\# Furnished herewith