Blueknight Energy Partners, L.P.
Form 10-Q
August 06, 2015

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

FORM 10-Q

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

For the quarterly period ended June 30, 2015

OR

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

For the transition period from __________ to _________

Commission File Number 001-33503

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

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

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

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

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

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 30, 2015, there were 30,158,619 Series A Preferred Units and 32,945,556 common units outstanding.

Table of Contents

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, 2014 (unaudited)	As of June 30, 2015
ASSETS		
Current assets:		
Cash and cash equivalents	$2,661	$2,354
Accounts receivable, net of allowance for doubtful accounts of $222 and $22 at December 31, 2014 and June 30, 2015, respectively	9,051	14,587
Receivables from related parties, net of allowance for doubtful accounts of $225 at both dates	2,316	2,668
Prepaid insurance	1,582	3,726
Investments	2,079	—
Other current assets	3,805	4,095
Total current assets	21,494	27,430
Property, plant and equipment, net of accumulated depreciation of $192,440 and $203,999 at December 31, 2014 and June 30, 2015, respectively	310,163	324,021
Investment in unconsolidated affiliate	20,381	19,461
Goodwill	7,216	10,727
Debt issuance costs, net	3,085	2,648
Intangibles and other assets, net	2,056	3,759
Total assets	$364,395	$388,046
LIABILITIES AND PARTNERS’ CAPITAL		
Current liabilities:		
Accounts payable	$7,626	$12,137
Accrued interest payable	233	189
Accrued property taxes payable	2,046	2,486
Unearned revenue	1,531	1,636
Unearned revenue with related parties	909	765
Accrued payroll	6,520	4,821
Other current liabilities	3,204	4,796
Total current liabilities	22,069	26,830
Unearned revenue with related parties, noncurrent	116	98
Other long-term liabilities	3,620	4,901
Interest rate swap liabilities	2,634	3,663
Long-term debt	216,000	243,000
Commitments and contingencies (Note 12)		
Partners’ capital:		
Series A Preferred Units (30,158,619 units issued and outstanding for both dates)	204,599	204,599
Common unitholders (32,774,163 and 32,915,481 units issued and outstanding at December 31, 2014 and June 30, 2015, respectively)	525,767	515,602

General partner interest (1.8% interest with 1,127,755 general partner units outstanding at both dates)	(610,410)	(610,647)
Total Partners’ capital	119,956	109,554
Total liabilities and Partners’ capital	$364,395	$388,046

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

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,	
	2014	2015	2014	2015
	(unaudited)			
Service revenue:				
Third party revenue	$35,197	$36,389	$69,433	$68,512
Related party revenue	10,600	10,185	22,806	20,418
Total revenue	45,797	46,574	92,239	88,930
Expense:				
Operating	34,475	33,383	69,976	65,768
General and administrative	4,371	4,667	8,857	9,644
Total expense	38,846	38,050	78,833	75,412
Gain (loss) on sale of assets	575	(40)	972	264
Operating income	7,526	8,484	14,378	13,782
Other income (expense):				
Equity earnings in unconsolidated affiliate	258	1,283	54	1,939
Interest expense (net of capitalized interest of $80, $50, $160 and $73, respectively)	(4,031)	(1,951)	(6,686)	(6,234)
Income before income taxes	3,753	7,816	7,746	9,487
Provision for income taxes	134	106	234	198
Net income	$3,619	$7,710	$7,512	$9,289
Allocation of net income for calculation of earnings per unit:				
General partner interest in net income	$96	$241	$189	$344
Preferred interest in net income	$5,391	$5,391	$10,782	$10,782
Income (loss) available to limited partners	$(1,868)	$2,078	$(3,459)	$(1,837)
Basic and diluted net income (loss) per common unit	$(0.08)	$0.06	$(0.15)	$(0.05)
Weighted average common units outstanding - basic and diluted	22,925	32,915	22,910	32,905

The accompanying notes are an integral part of these 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, 2014	$ 525,767	$ 204,599	$ (610,410)	$ 119,956
Net income (loss)	(1,655)	10,782	162	9,289
Equity-based incentive compensation	719	—	13	732
Profits interest contribution	—	—	74	74
Distributions	(9,229)	(10,782)	(486)	(20,497)
Balance, June 30, 2015	$ 515,602	$ 204,599	$ (610,647)	$ 109,554

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

3

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

	Six Months ended June 30, 2014	2015
	(unaudited)	
Cash flows from operating activities:		
Net income	$7,512	$9,289
Adjustments to reconcile net income to net cash provided by operating activities:		
Provision for uncollectible receivables from third parties	156	(200)
Depreciation and amortization	12,771	13,384
Amortization and write-off of debt issuance costs	398	437
Unrealized loss related to interest rate swaps	2,002	1,029
Gain on sale of assets	(972)	(264)
Equity-based incentive compensation	529	732
Equity earnings in unconsolidated affiliate	(54)	(1,939)
Distributions from unconsolidated affiliate	—	2,321
Gain related to investments	—	(267)
Changes in assets and liabilities		
Increase in accounts receivable	(474)	(5,336)
Decrease (increase) in receivables from related parties	18	(352)
Decrease in prepaid insurance	1,016	1,295
Decrease (increase) in other current assets	336	(290)
Decrease (increase) in other assets	114	(1,720)
Increase (decrease) in accounts payable	(791)	1,586
Decrease in accrued interest payable	(312)	(44)
Increase in accrued property taxes	310	440
Increase in unearned revenue	1,973	1,465
Increase (decrease) in unearned revenue from related parties	125	(162)
Decrease in accrued payroll	(2,284)	(1,699)
Decrease in other accrued liabilities	(2,499)	(481)
Net cash provided by operating activities	19,874	19,224
Cash flows from investing activities:		
Acquisitions	—	(13,895)
Capital expenditures	(18,236)	(14,516)
Proceeds from sale of assets	1,086	864
Distributions from unconsolidated affiliate	—	538
Proceeds from sale of investments	—	2,346
Net cash used in investing activities	(17,150)	(24,663)
Cash flows from financing activities:		
Payment on insurance premium financing agreement	(1,235)	(1,445)
Borrowings under credit facility	31,000	65,000
Payments under credit facility	(17,000)	(38,000)
Capital contribution related to profits interest	74	74
Distributions	(17,147)	(20,497)
Net cash provided by (used in) financing activities	(4,308)	5,132
Net decrease in cash and cash equivalents	(1,584)	(307)
Cash and cash equivalents at beginning of period	3,182	2,661
Cash and cash equivalents at end of period	$1,598	$2,354

Supplemental disclosure of cash flow information:		
Increase in accounts payable related to purchase of property, plant and equipment	$ 855	$ 2,925
Increase in accrued liabilities related to insurance premium financing agreement	$ 2,494	$ 3,439

The accompanying notes are an integral part of these 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-three states. The Partnership provides integrated terminalling, storage, processing, gathering and transportation services for companies engaged in the production, distribution and marketing of crude oil and asphalt products. The Partnership manages its operations through four operating segments: (i) asphalt 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, 2014 and 2015, the condensed consolidated statement of changes in partners’ capital for the six months ended June 30, 2015, the condensed consolidated statements of cash flows for the six months ended June 30, 2014 and 2015, and the condensed consolidated balance sheet as of June 30, 2015 are unaudited. In the opinion of management, the unaudited 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 2014 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, 2014 filed with the Securities and Exchange Commission (the “SEC”) on March 11, 2015 (the “2014 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 4 of the Notes to Consolidated Financial Statements in its 2014 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 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 the unconsolidated affiliate on the condensed consolidated balance sheets. Distributions to the Partnership reduce the carrying value of its investment and are reflected in the Partnership’s condensed consolidated statements of cash flows in the line item “Distributions from unconsolidated affiliate.” In turn, contributions will increase the carrying value of the Partnership’s investment and will be reflected in the Partnership’s condensed consolidated statements of cash flows in investing activities.

3. PROPERTY, PLANT AND EQUIPMENT

	Estimated Useful Lives (Years)	December 31, 2014	June 30, 2015
		(dollars in thousands)	
Land	N/A	$ 18,292	$ 19,567
Land improvements	10-20	6,398	6,465
Pipelines and facilities	5-30	168,537	176,880
Storage and terminal facilities	10-35	240,004	252,018
Transportation equipment	3-10	13,557	12,722
Office property and equipment and other	3-20	28,958	29,164
Pipeline linefill and tank bottoms	N/A	10,186	10,186
Construction-in-progress	N/A	16,671	21,018
Property, plant and equipment, gross		502,603	528,020
Accumulated depreciation		(192,440)	(203,999)
Property, plant and equipment, net		$ 310,163	$ 324,021

Depreciation expense for the three months ended June 30, 2014 and 2015 was $6.4 million and $6.7 million, respectively, and depreciation expense for the six months ended June 30, 2014 and 2015 was $12.8 million and $13.4 million, respectively.

4. 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).

As of July 30, 2015, approximately $236.0 million of revolver borrowings and $1.2 million of letters of credit were outstanding under the credit facility, leaving the Partnership with approximately $162.8 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 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:

- after the Partnership delivers the Knight Warrior Pipeline Initiation Certificate (as defined in the credit agreement, but generally meaning that the Partnership has spent at least $15.0 million of the projected capital expenditures for its Knight Warrior pipeline project), the maximum permitted consolidated total leverage ratio is 5.00 to 1.00 for the fiscal quarters ending March 31, 2015 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;
- after the Partnership delivers the Knight Warrior Pipeline Leverage Election Certificate (as defined in the credit agreement, but generally meaning that the Partnership has spent at least 50% of the projected capital expenditures for the Knight Warrior pipeline project), 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 Partnership delivers the Knight Warrior Pipeline Initiation Certificate, the maximum permitted consolidated total leverage ratio is 5.50 to 1.00 for the fiscal quarters ending March 31, 2015 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, 2015, the Partnership's consolidated total leverage ratio was 3.50 to 1.00 and the consolidated interest coverage ratio was 7.31 to 1.00. The Partnership was in compliance with all covenants of its credit agreement as of June 30, 2015.

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 6 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 have letters of credit issued under the credit agreement.

The Partnership capitalized no debt issuance costs for the three months ended June 30, 2014 and 2015 and the six months ended June 30, 2014 and 2015. 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 each of the three months ended June 30, 2014 and 2015 was $0.2 million. Interest expense related to debt issuance cost amortization for each of the six months ended June 30, 2014 and 2015 was $0.4 million.

During the three months ended June 30, 2014 and 2015, the weighted average interest rate under the Partnership's credit agreement was 3.40% and 3.38%, respectively, resulting in interest expense of approximately $2.5 million and $2.0 million, respectively. During the six months ended June 30, 2014 and 2015, the weighted average interest rate under the Partnership's credit agreement was 3.41% and 3.40%, respectively, resulting in interest expense of approximately $4.8 million and $3.9 million, respectively. As of June 30, 2015, borrowings under the Partnership's amended and restated credit agreement bore interest at a weighted average interest rate of 3.34%.

During the three months ended June 30, 2014 and 2015, the Partnership capitalized interest of $0.1 million and less than $0.1 million, respectively. During the six months ended June 30, 2014 and 2015, the Partnership capitalized interest of $0.2 million and $0.1 million, respectively.

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 will pay a fixed rate of 1.97% and will receive one-month LIBOR with monthly settlement. During the three and six months ended June 30, 2015, the Partnership recorded swap interest expense of $0.8 million and $1.4 million respectively. The Partnership had no swap interest expense for the three and six months ended June 30, 2014. The fair market value of the interest rate swaps at December 31, 2014 and June 30, 2015 is a liability of $2.6 million and $3.7 million, respectively, and is recorded in long-term interest rate swap liabilities on the 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 condensed consolidated statements of operations.

5. 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 (loss) per common unit (in thousands, except per unit data):

	Three Months ended June 30,		Six Months ended June 30,	
	2014	2015	2014	2015
Net income	$3,619	$7,710	$7,512	$9,289
General partner interest in net income	96	241	189	344
Preferred interest in net income	5,391	5,391	10,782	10,782
Income (loss) available to limited partners	$(1,868)	$2,078	$(3,459)	$(1,837)
Basic and diluted weighted average number of units:				
Common units	22,925	32,915	22,910	32,905
Restricted and phantom units	727	741	606	652
Basic and diluted net income (loss) per common unit	$(0.08)	$0.06	$(0.15)	$(0.05)

6. 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 21, 2015, 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, 2015. The Partnership will pay this distribution on the preferred units on August 14, 2015 to unitholders of record as of August 4, 2015.

In addition, on July 21, 2015, the Board declared a cash distribution of $0.1425 per unit on its outstanding common units. The distribution will be paid on August 14, 2015 to unitholders of record on August 4, 2015. The distribution is for the three months ended June 30, 2015. The total distribution will be approximately $5.1 million, with approximately $4.7 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.

7. RELATED PARTY TRANSACTIONS

The Partnership provides crude oil gathering, transportation, terminalling and storage services to Vitol as well as certain operating, strategic assessment, economic evaluation and project design services. For the three months ended June 30, 2014 and 2015, the Partnership recognized revenues of $10.3 million and $9.9 million, respectively, for services provided to Vitol. For the six months ended June 30, 2014 and 2015, the Partnership recognized revenues of

$22.4 million and $19.8 million, respectively, for services provided to Vitol. As of December 31, 2014 and June 30, 2015, the Partnership had receivables from Vitol of $2.3 million and $2.6 million, net of allowance for doubtful accounts. As of December 31, 2014 and June 30, 2015, the Partnership had unearned revenues from Vitol of $1.0 million and $0.9 million, respectively.

The Partnership also provides operating and administrative services to Advantage Pipeline. For each of the three months ended June 30, 2014 and 2015, the Partnership earned revenues of $0.3 million for services provided to Advantage Pipeline. For the six months ended June 30, 2014 and 2015, the Partnership earned revenues of $0.4 million and $0.6 million, respectively, for services provided to Advantage Pipeline. As of December 31, 2014 and June 30, 2015, the Partnership had receivables from Advantage Pipeline of less than $0.1 million and $0.1 million, respectively.

8. 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 under ASC 718 - Stock Compensation and, accordingly, the fair value of the awards as of the grant date is expensed over the vesting period.

In each of December 2012, 2013 and 2014, 7,500 restricted common units were granted which vest in one-third increments over three years. These grants were made in connection with the anniversary of the independent directors joining the Board. The grant date fair value of the restricted units for the 2012 and 2014 grants was less than $0.1 million while the grant date fair value of the restricted units for the 2013 grant was $0.1 million.

In March 2013, 2014 and 2015, grants for 251,106, 276,773 and 266,076 phantom units, respectively, were made, which vest on January 1, 2016, January 1, 2017 and January 1, 2018, respectively. These grants are equity awards under ASC 718 – Stock Compensation, and, accordingly, the fair value of the awards as of the grant date is expensed over the vesting period. The weighted average grant date fair-value of the awards is $8.75, $9.06 and $7.74 per unit, respectively, which is the closing market price on the grant date of the awards. The value of these award grants was approximately $2.2 million, $2.5 million and $2.1 million respectively, on their grant date. The unrecognized estimated compensation cost of outstanding phantom units at June 30, 2015 was $3.2 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, 2015 was $1.2 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, 2014 and 2015 was $0.6 million and $0.7 million, respectively. The Partnership's equity-based incentive compensation expense for the six months ended June 30, 2014 and 2015 was $1.0 million and $1.2 million, respectively.

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

	Number of Units	Weighted Average Grant Date Fair Value
Nonvested at December 31, 2014	1,020,264	$ 7.46
Granted	266,076	7.74
Vested	222,800	6.76
Forfeited	24,024	8.75
Nonvested at June 30, 2015	1,039,516	$ 7.65

9. 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 for each of the three months ended June 30, 2014 and 2015 for discretionary contributions under the 401(k) Plan. The Partnership recognized expense of $0.7 million and $0.8 million, respectively, for the six months ended June 30, 2014 and 2015 for discretionary contributions under the 401(k) Plan.

The Partnership may also make annual lump-sum contributions to the 401(k) Plan irrespective of the employee's contribution match. The Partnership may make a discretionary annual contribution in the form of profit sharing calculated as a percentage of an employee's eligible compensation. This contribution is retirement income under the qualified 401(k) Plan. Annual profit sharing contributions to the 401(k) Plan are submitted to and approved by the Board. The Partnership recognized expense of $0.2 million and $0.1 million for the three months ended June 30, 2014 and 2015, respectively, for discretionary profit sharing contributions under the 401(k) Plan. The Partnership recognized expense of $0.3 million for each of the six months ended June 30, 2014 and 2015 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 each of the three and six months ended June 30, 2015 in connection with the Unit Purchase Plan.

10. FAIR VALUE MEASUREMENTS

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

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

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

This hierarchy requires the use of observable market data, when available, 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):

Description	Fair Value Measurements as of December 31, 2014			
	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	$2,634	$—	$2,634	$—
Total	$2,634	$—	$2,634	$—

Description	Fair Value Measurements as of June 30, 2015			
	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	$3,663	$—	$3,663	$—
Total	$3,663	$—	$3,663	$—

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, 2015, 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, 2015 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.

11. OPERATING SEGMENTS

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

ASPHALT SERVICES —The Partnership provides asphalt product and residual fuel terminalling, storage and blending services at its 43 terminalling and storage facilities located in twenty-two 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 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 and 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,	
	2014	2015	2014	2015
Asphalt Services				
Service revenue				
Third party revenue	$ 16,292	$ 19,016	$ 30,739	$ 33,628
Related party revenue	444	253	701	405
Total revenue for reportable segments	16,736	19,269	31,440	34,033
Operating expense (excluding depreciation and amortization)	6,635	6,607	13,487	12,758
Operating margin (excluding depreciation and amortization)	10,101	12,662	17,953	21,275
Total assets (end of period)	$ 98,188	$ 108,426	$ 98,188	$ 108,426
Crude Oil Terminalling and Storage Services				
Service revenue				
Third party revenue	$ 2,305	$ 3,643	$ 5,145	$ 6,197
Related party revenue	3,131	2,934	7,645	6,010
Total revenue for reportable segments	5,436	6,577	12,790	12,207
Operating expense (excluding depreciation and amortization)	1,005	1,695	1,974	3,257
Operating margin (excluding depreciation and amortization)	4,431	4,882	10,816	8,950
Total assets (end of period)	$ 67,428	$ 68,814	$ 67,428	$ 68,814
Crude Oil Pipeline Services				
Service revenue				
Third party revenue	$ 4,434	$ 4,238	$ 7,533	$ 8,513
Related party revenue	1,949	2,607	3,836	4,990
Total revenue for reportable segments	6,383	6,845	11,369	13,503
Operating expense (excluding depreciation and amortization)	4,735	4,825	9,117	8,733
Operating margin (excluding depreciation and amortization)	1,648	2,020	2,252	4,770
Total assets (end of period)	$ 169,480	$ 194,293	$ 169,480	$ 194,293
Crude Oil Trucking and Producer Field Services				
Service revenue				
Third party revenue	$ 12,166	$ 9,492	$ 26,016	$ 20,174
Related party revenue	5,076	4,391	10,624	9,013
Total revenue for reportable segments	17,242	13,883	36,640	29,187
Operating expense (excluding depreciation and amortization)	15,646	13,518	32,627	27,636
Operating margin (excluding depreciation and amortization)	1,596	365	4,013	1,551
Total assets (end of period)	$ 25,258	$ 16,513	$ 25,258	$ 16,513
Total operating margin (excluding depreciation and amortization)(1)	$ 17,776	$ 19,929	$ 35,034	$ 36,546

(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,	
	2014	2015	2014	2015
Operating margin (excluding depreciation and amortization)	$17,776	$19,929	$35,034	$36,546
Depreciation and amortization	(6,454)	(6,738)	(12,771)	(13,384)
General and administrative expenses	(4,371)	(4,667)	(8,857)	(9,644)
Gain (loss) on sale of assets	575	(40)	972	264
Interest expense	(4,031)	(1,951)	(6,686)	(6,234)
Equity earnings in unconsolidated affiliate	258	1,283	54	1,939
Income before income taxes	$3,753	$7,816	$7,746	$9,487

12. 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.

On October 27, 2008, Keystone Gas Company ("Keystone") filed suit against the Partnership in Oklahoma State District Court in Creek County alleging that it is the rightful owner of certain segments of the Partnership's pipelines and related rights of way, located in Payne and Creek Counties, that the Partnership acquired from SemGroup Corporation ("SemCorp") in connection with the Partnership's initial public offering in 2007. Keystone seeks to quiet title to various rights of way and pipelines and seeks damages up to the net profits derived from the disputed pipelines. There has been no determination of the extent of potential damages for the Partnership's use of such pipelines. The Partnership has filed a counterclaim against Keystone alleging that it is wrongfully using a segment of a pipeline that is owned by the Partnership in Payne and Creek Counties. The Partnership intends to vigorously defend these claims. No trial date has been set by the court. The parties are engaged in discovery as well as settlement negotiations. The Partnership believes any settlement will not have a material adverse effect on the Partnership's financial condition or results of operations.

On February 6, 2012, the Partnership filed suit against SemCorp and others in Oklahoma County District Court. In the suit, the Partnership is seeking a judgment that SemCorp immediately return approximately 140,000 barrels of crude oil linefill belonging to the Partnership, and the Partnership is seeking judgment in an amount in excess of $75,000 for actual damages, special damages, punitive damages, pre-judgment interest, reasonable attorney's fees and costs, and such other relief that the Court deems equitable and just. On March 22, 2012, SemCorp filed a motion to dismiss and transfer to Tulsa County. On April 18, 2012, SemCorp filed a motion for summary judgment, and, on May 1, 2012, the District Court of Oklahoma County ordered a transfer to Tulsa County. The Partnership contested SemCorp's motion for summary judgment, which was referred to a Special Master for report and recommendation. On June 10, 2013, the Special Master filed a report with the District Court of Tulsa County, finding a shortage in the Partnership's Cushing Terminal and Oklahoma pipeline system of approximately 148,000 barrels and an excess of approximately 130,000 in SemCorp's physical inventory. The Special Master noted that she was unable to more precisely trace the shortage and length (excess held by SemCorp) due to the manner in which SemCorp operated the Cushing Terminal and maintained related records. On June 25, 2013, the Partnership filed a notice of non-objection and motion to adopt the Special Master's report, which was granted on February 12, 2014. On September 17, 2013, the Partnership filed a motion for summary judgment as to the liability of SemCorp for the Partnership's claims for breach of contract and negligence by a bailee. On October 7, 2013, SemCorp renewed its motion for summary judgment, which the Partnership timely opposed. On February 20, 2014, the Court denied summary judgment motions of both SemCorp and the Partnership. The Court allowed for additional discovery to take place and referred all discovery matters to the Special Master, as appropriate, and made other procedural rulings. The Partnership reasserted its fraud claims in accordance with the Court’s directives. Discovery proceedings continue and the Partnership has determined that SemCorp knew of its excess inventory and sold this inventory during the period prior to the Partnership’s filing of the lawsuit while denying that the Partnership claims had any validity and failing to disclose the excess to the Partnership. The discovery period has been completed and the Court has been presented with various motions for consideration. Depending on timing of the Court’s rulings and the results of mediation, trial will likely be scheduled for 2016. The Partnership intends to seek additional damages from SemCorp related to various injuries to the Partnership as a result of SemCorp’s refusal to return the Partnership’s crude oil or to pay the Partnership for the fair market value of the missing oil.

On November 1, 2014, a multi-vehicular accident occurred resulting in the death of an employee of the Partnership and allegations of injuries to third parties and injury to property. Litigation has been filed by injured third parties. The matter has been submitted to the Partnership's insurance carriers and the retentions have been reserved. The ultimate outcome of this matter cannot be determined at this time.

On February 13, 2015, a multi-vehicular accident occurred resulting in injury to third parties and two employees of the Partnership as well as property damage. Litigation has been filed by injured third parties. The matter has been submitted to the Partnership's insurance carriers and the retentions have been reserved. The ultimate outcome of this matter cannot be determined at this time.

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 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.

13. 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, 2015 are presented below (dollars in thousands):

Deferred tax assets	
Difference in bases of property, plant and equipment	$ 923
Deferred tax asset	923
Less: valuation allowance	(923)
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, 2015.

14. RECENTLY ISSUED ACCOUNTING STANDARDS

In April 2014, the FASB issued ASU 2014-08, "Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity." The amendments in this update change the criteria for reporting discontinued operations for all public and nonpublic entities. The amendments also require new disclosures about discontinued operations and disposals of components of an entity that do not qualify for discontinued operations reporting. The amendments in this update are effective for fiscal years, and interim periods within those years, beginning after December 15, 2014. The Partnership adopted this update for the period ending March 31, 2015, and there was no impact on the Partnership's financial position, results of operations or cash flows.

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 July 2015, the FASB decided to delay the effective date of this update. The amendments in this update are effective for fiscal years, and interim periods within those years, beginning after December 15, 2017. 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 August 2014, the FASB issued ASU 2014-15, "Presentation of Financial Statements - Going Concern." The update provides U.S. GAAP guidance on management's responsibility in evaluating whether there is substantial doubt about a company's ability to continue as a going concern and about related footnote disclosures. For each reporting period, management will be required to evaluate whether there are conditions or events that raise substantial doubt about a company's ability to continue as a going concern within one year from the date the financial statements are issued. The amendments in this update are effective for the annual period ending after December 15, 2016, and for annual periods and interim periods thereafter. The Partnership is evaluating the impact of this guidance, which will be adopted beginning with the Partnership's annual report for the period ending December 31, 2016.

On April 7, 2015, the FASB issued ASU 2015-03, "Simplifying the Presentation of Debt Issuance Costs", which requires debt issuance costs to be presented in the balance sheet as a direct deduction from the associated debt liability. This update is effective for financial statements issued for fiscal years beginning after December 15, 2015, 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, 2016.

On April 30, 2015, the FASB issued ASU 2015-06, "Effects on Historical Earnings per Unit of Master Limited Partnership Dropdown Transactions." Master limited partnerships (MLPs) apply the two-class method to calculate earnings per unit (EPU) because the general partner, limited partners, and incentive distribution rights holders each participate differently in the distribution of available cash. When a general partner transfers (or "drops down") net assets to a master limited partnership and that transaction is accounted for as a transaction between entities under common control, the statements of operations of the master limited partnership are adjusted retrospectively to reflect the dropdown transaction as if it occurred on the earliest date during which the entities were under common control.

The amendments in ASU 2015-06 specify that for purposes of calculating historical EPU under the two-class method, the earnings (losses) of a transferred business before the date of a dropdown transaction should be allocated entirely to the general partner interest, and previously reported EPU of the limited partners would not change as a result of a dropdown transaction. Qualitative disclosures about how the rights to the earnings (losses) differ before and after the dropdown transaction occurs also are required. This update is effective for financial statements issued for fiscal years beginning after December 15, 2015, 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, 2016.

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, 2014, which was filed with the Securities and Exchange Commission (the "SEC") on March 11, 2015 (the "2014 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 2014 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-three states. We provide integrated terminalling, storage, gathering and transportation services for companies engaged in the production, distribution and marketing of crude oil and liquid asphalt cement. We manage our operations through four operating segments: (i) asphalt 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 on Future Revenues

From August 2014 to July 2015, the market price of West Texas Intermediate crude oil has decreased approximately 50%, from approximately $100 per barrel to approximately $50 per barrel. 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). We expect this price and curve change to have the following near-term impacts on our operating segments:

Asphalt Services - The asphalt industry tends to benefit from a lower crude oil price environment and strong economy. We expect our asphalt services customers to acquire and store additional asphalt product in the lower crude oil price environment (which tends to correlate somewhat with asphalt prices), and we expect that municipalities will be able to purchase more product due to the lower price of asphalt. As a result, we expect increased product throughput at our facilities in the near term, which may ultimately increase the revenues generated by our asphalt 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: (1) renew expiring contracts at average rates higher than those in place at September 30, 2014, (2) increase our weighted average remaining contract term to 19 months at June 30, 2015 as compared to 9 months at September 30, 2014 and (3) 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.

Crude Oil Pipeline Services - We do not currently expect the recent crude oil price changes to have a significant impact on our crude oil pipeline services operating segment as a significant portion of the capacity of our Mid-Continent and Eagle North systems are contracted under throughput and deficiency agreements. In addition, throughput volume on the Pecos River Pipeline, in which we have a 30% equity ownership interest, is expected to continue to increase in 2015.

Crude Oil Trucking and Producer Field Services - We may experience downward rate pressure in our trucking and producer field services business as producers and marketers attempt to renegotiate service rates to preserve their operating margins. This operating segment may be negatively impacted in the longer term if lower crude oil prices are sustained and result in decreased crude oil production and demand for crude oil transportation services.

Our Revenues

Our revenues consist of (i) terminalling and storage revenues, (ii) gathering, transportation and producer field services revenues and (iii) fuel surcharge revenues. For the three months ended June 30, 2015, we derived approximately $9.9 million and $0.3 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 services and (ii) crude oil terminalling and storage services.

We have leases and storage agreements with third party customers for all of our 43 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 30, 2015, we had approximately 5.9 million barrels of crude oil storage under service contracts with remaining terms ranging from 4 months to 22 months, including 0.9 million barrels of crude oil storage contracts that expire in 2015. 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 2015; 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, 2015, we transported approximately 55,000 barrels per day on our pipelines as compared to 53,000 barrels per day during the three months ended June 30, 2014. Vitol accounted for 30% and 25% of volumes transported in our pipelines in the three months ended June 30, 2015 and 2014, respectively.

For the three months ended June 30, 2015, we transported approximately 55,000 barrels per day on our crude oil transport trucks, a decrease of 17% as compared to the three months ended June 30, 2014. Vitol accounted for approximately 45% and 43% of volumes transported by our crude oil transport trucks in the three months ended June 30, 2015 and 2014, respectively.

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.

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 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 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, 2015.

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 21, 2015, 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, 2015. We will pay this distribution on the preferred units on August 14, 2015 to unitholders of record as of August 4, 2015.

In addition, on July 21, 2015, the Board approved a cash distribution of $0.1425 per unit on our outstanding common units. The distribution will be paid on August 14, 2015 to unitholders of record on August 4, 2015. The distribution is for the three months ended June 30, 2015. The total distribution to be paid is approximately $5.1 million, with approximately $4.7 million and less than $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, 2014 and 2015, 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)	2014	2015	2014	2015	$	%	$	%
Operating Margin, excluding depreciation and amortization:								
Asphalt services operating margin	$10,101	$12,662	$17,953	$21,275	2,561	25 %	3,322	19 %
Crude oil terminalling and storage operating margin	4,431	4,882	10,816	8,950	451	10 %	(1,866)	(17)%
Crude oil pipeline services operating margin	1,648	2,020	2,252	4,770	372	23 %	2,518	112 %
Crude oil trucking and producer field services operating margin	1,596	365	4,013	1,551	(1,231)	(77)%	(2,462)	(61)%
Total operating margin, excluding depreciation and amortization	17,776	19,929	35,034	36,546	2,153	12 %	1,512	4 %
Depreciation and amortization	(6,454)	(6,738)	(12,771)	(13,384)	(284)	(4)%	(613)	(5)%
General and administrative expense	(4,371)	(4,667)	(8,857)	(9,644)	(296)	(7)%	(787)	(9)%
Gain (loss) on sale of assets	575	(40)	972	264	(615)	(107)%	(708)	(73)%
Operating income	7,526	8,484	14,378	13,782	958	13 %	(596)	(4)%
Other income (expense):								
Equity earnings in unconsolidated entity	258	1,283	54	1,939	1,025	397 %	1,885	3,491 %
Interest expense	(4,031)	(1,951)	(6,686)	(6,234)	2,080	52 %	452	7 %
Income tax expense	(134)	(106)	(234)	(198)	28	21 %	36	15 %
Net income	$3,619	$7,710	$7,512	$9,289	4,091	113 %	1,777	24 %

Total operating margin excluding depreciation and amortization increased from 2014 to 2015 due to several factors, including new crude oil storage and terminalling contracts, increased volumes on our Mid-Continent system, our acquisition of an asphalt terminal in Cheyenne, Wyoming, and renegotiated throughput fees for some of our asphalt facilities.

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

Analysis of Operating Segments

Asphalt services segment

Our asphalt 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 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)	2014	2015	2014	2015	$	%	$	%
Revenue								
Third Party Revenue	$16,292	$19,016	$30,739	$33,628	2,724	17 %	2,889	9 %
Related Party Revenue	444	253	701	405	(191)	(43)%	(296)	(42)%
Total Revenue	16,736	19,269	31,440	34,033	2,533	15 %	2,593	8 %
Operating Expense (excluding depreciation and amortization)	6,635	6,607	13,487	12,758	28	— %	729	5 %
Operating Margin (excluding depreciation and amortization)	$10,101	$12,662	$17,953	$21,275	2,561	25 %	3,322	19 %

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

- Third party revenues increased for the three and six months ended June 30, 2015 as compared to the three and six months ended June 30, 2014 primarily due to renegotiated throughput fees for some of our facilities as well as revenues earned in relation to an asphalt terminalling facility we acquired in May 2015.

- Related party revenues decreased due to lower overall contracted storage from short-term spot contracts during the three and six months ended June 30, 2015 as compared to the three and six months ended June 30, 2014.

23

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)	2014	2015	2014	2015	$	%	$	%
Revenue								
Third Party Revenue	$2,305	$3,643	$5,145	$6,197	1,338	58 %	1,052	20 %
Related Party Revenue	3,131	2,934	7,645	6,010	(197)	(6)%	(1,635)	(21)%
Total Revenue	5,436	6,577	12,790	12,207	1,141	21 %	(583)	(5)%
Operating Expense (excluding depreciation and amortization)	1,005	1,695	1,974	3,257	(690)	(69)%	(1,283)	(65)%
Operating Margin (excluding depreciation and amortization)	$4,431	$4,882	$10,816	$8,950	451	10 %	(1,866)	(17)%
Average crude oil stored per month at our Cushing terminal (in thousands of barrels)	1,482	5,977	2,331	5,167	4,495	303 %	2,836	122 %
Average crude oil delivered to our Cushing terminal (in thousands of barrels per day)	73	109	93	117	36	49 %	24	26 %

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

- Revenues increased due to the timing of 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.

- As of July 31, 2015, we had approximately 5.9 million barrels of crude oil storage under service contracts with remaining terms of up to 22 months, including 0.9 million barrels of crude oil storage contracts that expire in 2015. Storage contracts with Vitol represent 2.4 million barrels of crude oil storage capacity under contract.

- Operating expenses for both comparable periods in 2015 were higher as compared to 2014 primarily as a result of the timing of tank inspections and related maintenance and repair, increases in utility expenses, as well as an increase in the percentage of total corporate shared services costs incurred by the crude oil terminalling and storage services segment.

24

Crude oil pipeline services segment

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

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

Operating results	Three Months ended June 30,		Six Months ended June 30,		Favorable/(Unfavorable)			
					Three Months		Six Months	
(in thousands)	2014	2015	2014	2015	$	%	$	%
Revenue								
Third Party Revenue	$4,434	$4,238	$7,533	$8,513	(196)	(4)%	980	13%
Related Party Revenue	1,949	2,607	3,836	4,990	658	34%	1,154	30%
Total Revenue	6,383	6,845	11,369	13,503	462	7%	2,134	19%
Operating Expense (excluding depreciation and amortization)	4,735	4,825	9,117	8,733	(90)	(2)%	384	4%
Operating Margin (excluding depreciation and amortization)	$1,648	$2,020	$2,252	$4,770	372	23%	2,518	112%
Average throughput volume (in thousands of barrels per day)								
Mid-Continent	19	23	19	22	4	21%	3	16%
Eagle North	17	15	15	10	(2)	(12)%	(5)	(33)%
East Texas	17	17	17	17	—	—%	—	—%

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

- Revenues increased due primarily to increased volumes on our Mid-Continent system related to the Arbuckle pipeline system. Also impacting revenues was an increased tariff that was being charged through June of 2015 on certain barrels transported on our East Texas pipeline system under a throughput and deficiency agreement. The tariff will return to a lower rate after the second quarter of 2015, which will decrease the total revenues generated on the East Texas pipeline system.

- Operating expenses decreased for the six months ended June 30, 2015 as compared to the six months ended June 30, 2014 as a result of lower overall maintenance and repair costs as well as a decrease in the percentage of total corporate shared services costs incurred by the pipeline services segment.

- Average throughput on our Eagle North pipeline system was lower in the six months ended June 30, 2015 as compared to the six months ended June 30, 2014 as a result of a customer’s refinery being in turnaround. We anticipate volumes returning to historical averages in the near term.

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)	2014	2015	2014	2015	$	%	$	%
Revenue								
Third Party Revenue	$ 12,166	$ 9,492	$ 26,016	$ 20,174	(2,674)	(22)%	(5,842)	(22)%
Related Party Revenue	5,076	4,391	10,624	9,013	(685)	(13)%	(1,611)	(15)%
Total Revenue	17,242	13,883	36,640	29,187	(3,359)	(19)%	(7,453)	(20)%
Operating Expense (excluding depreciation and amortization)	15,646	13,518	32,627	27,636	2,128	14 %	4,991	15 %
Operating Margin (excluding depreciation and amortization)	$ 1,596	$ 365	$ 4,013	$ 1,551	(1,231)	(77)%	(2,462)	(61)%
Average volume (in thousands of barrels per day)	66	55	68	57	(11)	(17)%	(11)	(16)%

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

- Our operating margin declined for both the three and six months ended June 30, 2015 compared to the three and six months ended June 30, 2014 primarily due to an increase in pipeline connected barrels and lower crude oil prices causing a significant decrease in crude oil drilling, both of which adversely impacted volumes. In addition, a decrease in the average distance barrels were hauled for our customers decreased our overall rate per barrel charged and operating margin.

Other Income and Expenses

Depreciation and amortization. Depreciation and amortization increased slightly to $6.7 million for the three months ended June 30, 2015 compared to $6.5 million for the three months ended June 30, 2014. Depreciation and amortization increased$0.6 million to $13.4 million for the six months ended June 30, 2015 compared to $12.8 million for the six months ended June 30, 2014. This increase is primarily due to depreciation related to maintenance capital expenditures made throughout 2014 and the first quarter of 2015.

General and administrative expenses. General and administrative expenses increased by $0.3 million to $4.7 million for the three months ended June 30, 2015 compared to $4.4 million for the three months ended June 30, 2014. General and administrative expenses increased by $0.7 million to $9.6 million for the six months ended June 30, 2015 compared to $8.9 million for the six months ended June 30, 2014. This increase is primarily attributable to employee compensation-related expenses.

Gain on sale of assets. We had a loss on sale of assets of less than $0.1 million for the three months ended June 30, 2015 compared to a gain of $0.6 million for the three months ended June 30, 2014. Gain on sale of assets was $0.3 million for the six months ended June 30, 2015 compared to a gain of $1.0 million for the six months ended June 30,

2014. Gains and losses in 2014 and 2015 were primarily comprised of sales of surplus, used property and equipment. We do not anticipate the sale of equipment to have a significant impact on operating income for the remainder of 2015.

Equity earnings in unconsolidated affiliate. The equity earnings is attributed to our investment in Advantage Pipeline. This investment began generating equity earnings in the second quarter of 2014 upon the completion of the Crane West station, resulting in increased throughput on the pipeline. Earnings have increased in the three and six months ended June 30, 2015 as compared to the three and six months ended June 30, 2014 as a result of increased volumes transported by Advantage Pipeline.

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, 2015 decreased by $2.1 million compared to the three months ended June 30, 2014. During the three months ended June 30, 2015, we recorded unrealized gains due to the change in fair value of interest rate swaps of $0.8 million compared to unrealized losses of $1.6 million during the three months ended June 30, 2014. We also incurred interest expense in connection with settlement payments under our interest rate swap agreements of $0.8 million during the three months ended June 30, 2015. During the three months ended June 30, 2014, we incurred interest expense in connection with settlement payments under our interest rate swap agreements of less than $0.1 million. The interest rate swap agreements were entered into during the first quarter of 2014. In addition, interest on our credit facility decreased by $0.5 million due to decreases in our average debt outstanding and weighted average interest rate.

Total interest expense for the six months ended June 30, 2015 decreased by $0.5 million compared to the six months ended June 30, 2014. During the six months ended June 30, 2015, we recorded unrealized losses due to the change in fair value of interest rate swaps of $1.0 million compared to unrealized losses of $2.0 million during the six months ended June 30, 2014. We also incurred interest expense in connection with settlement payments under our interest rate swap agreements of $1.4 million during the six months ended June 30, 2015. During the six months ended June 30, 2014, we incurred interest expense in connection with settlement payments under our interest rate swap agreements of less than $0.1 million. In addition, interest on our credit facility decreased by $1.0 million due to decreases in our average debt outstanding and weighted average interest rate.

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, 2014 and 2015:

	Six Months ended June 30,	
	2014	2015
	(in millions)	
Net cash provided by operating activities	$ 19.9	$ 19.2
Net cash used in investing activities	(17.2)	(24.7)
Net cash provided by (used in) financing activities	(4.3)	5.1

Operating Activities. Net cash provided by operating activities was $19.2 million for the six months ended June 30, 2015, as compared to $19.9 million for the six months ended June 30, 2014. The six months ended June 30, 2015 includes $2.3 million in distributions received from Advantage Pipeline classified as a return on capital. This was partially offset by changes in working capital.

Investing Activities. Net cash used in investing activities was $24.7 million for the six months ended June 30, 2015, as compared to $17.2 million for the six months ended June 30, 2014. We acquired an asphalt terminalling facility for $13.9 million during the six months ended June 30, 2015. Capital expenditures for the six months ended June 30, 2015 and 2014 included maintenance capital expenditures of $3.1 million and $3.6 million, respectively, and expansion capital expenditures of $11.4 million and $14.6 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 November 2014 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 $5.1 million for the six months ended June 30, 2015, as compared to net cash used of $4.3 million for the six months ended June 30, 2014. Cash used in financing activities for the six months ended June 30, 2015 consisted primarily of $20.5 million in distributions to our unitholders, while cash provided by financing activities during the period included net borrowings on long term debt of $27.0 million. Financing activities for the six months ended June 30, 2014 consisted primarily of $17.1 million in distributions to our unitholders and net borrowings of $14.0 million.

Our Liquidity and Capital Resources

Cash flow from operations and our credit facility are our primary sources of liquidity. At June 30, 2015, we had a working capital surplus of $0.6 million. At June 30, 2015, we had approximately $156.0 million of availability under our revolving credit facility, although our ability to borrow such funds may be limited by the financial covenants in our credit facility. As of June 30, 2015, we could borrow up to $347.5 million, or an additional $103.5 million, under our credit facility within our covenant restrictions. As of July 30, 2015, we have aggregate unused commitments under our revolving credit facility of approximately $162.8 million and cash on hand of approximately $0.4 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 4 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 totaled $11.4 million in the six months ended June 30, 2015 compared to $14.6 million in the six months ended June 30, 2014. We currently expect our expansion capital expenditures for organic growth projects to be approximately $90.0 million to $110.0 million for all of 2015. Maintenance capital expenditures totaled $2.9 million, net of reimbursable expenditures of $0.2 million, in the six months ended June 30, 2015 compared to $2.9 million, net of reimbursable expenditures of $0.7 million, in the six months ended June 30, 2014. We currently expect maintenance capital expenditures to be approximately $9.0 million to $11.0 million, net of reimbursable expenditures, for all of 2015.

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 fiscal years, as of June 30, 2015, is as follows:

	Payments Due by Period				
Contractual Obligations	Total	Less than 1 year	1-3 years	4-5 years	More than 5 years
	(in millions)				
Debt obligations[1]	$264.8	$7.3	$7.3	$250.2	$—
Operating lease obligations	19.1	5.8	8.0	4.1	1.2
Employee contract obligations[2]	0.1	0.1	—	—	—

(1) Represents required future principal repayments of borrowings of $243.0 million and variable rate interest payments of $21.8 million. At June 30, 2015, our borrowings had an interest rate of approximately 3.34%. This interest rate was used to calculate future interest payments. All amounts outstanding under our credit agreement mature in June 2018.

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

Recent Accounting Pronouncements

For information regarding recent accounting developments that may affect our future financial statements, see Note 14 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 30, 2015, we had $236.0 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, 2015 is a liability of $3.7 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 three months ended June 30, 2015, the weighted average interest rate under our credit agreement was 3.38%.

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, 2015, 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 $0.4 million or decreased annual interest expense of $0.1 million.

Item 4. Controls and Procedures

Evaluation of disclosure controls and procedures. Our General Partner's management, including the Chief Executive Officer and Chief Financial Officer of our General Partner, evaluated, as of the end of the period covered by this report, the effectiveness of our disclosure controls and procedures as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer of our General Partner concluded that our disclosure controls and procedures, as of June 30, 2015, 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, 2015 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 12 to our unaudited condensed consolidated financial statements and is incorporated herein by reference thereto.

Item 1A. Risk Factors

Information about risk factors for the three months ended June 30, 2015 does not differ materially from that set forth in Part I, Item 1A, of our 2014 Form 10-K.

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 6, 2015	By:	/s/ Alex G. Stallings Alex G. Stallings Chief Financial Officer and Secretary
Date:	August 6, 2015	By:	/s/ James R. Griffin James R. Griffin Chief Accounting Officer

INDEX TO EXHIBITS

Exhibit Number	Exhibit Name
3.1	Amended and Restated Certificate of Limited Partnership of the Partnership, dated November 19, 2009 but effective as of December 1, 2009 (filed as Exhibit 3.1 to the Partnership's Current Report on Form 8-K, filed November 25, 2009, 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).
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, 2015, formatted in XBRL (eXtensible Business Reporting Language): (i) Document and Entity Information; (ii) Unaudited Condensed Consolidated Balance Sheets as of December 31, 2014 and June 30, 2015; (iii) Unaudited Condensed Consolidated Statements of Operations for the three and six months ended June 30, 2014 and 2015; (iv) Unaudited Condensed Consolidated Statement of Changes in Partners' Capital for the six months ended June 30, 2015; (v) Unaudited Condensed Consolidated Statements of Cash Flows for the six months ended June 30, 2014 and 2015; and (vi) Notes to Unaudited Condensed Consolidated Financial Statements.

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* Filed herewith.

\# Furnished herewith