Blueknight Energy Partners, L.P.
Form 10-Q
August 07, 2013

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, 2013

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 Q 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 Q 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 Q
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 Q

As of August 2, 2013, there were 30,159,958 Series A Preferred Units and 22,682,702 common units outstanding.

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PART I. FINANCIAL INFORMATION

Item 1. Unaudited Financial Statements

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

	As of December 31, 2012 (unaudited)	As of June 30, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	$3,177	$4,848
Accounts receivable, net of allowance for doubtful accounts of $469 and $72 at December 31, 2012 and June 30, 2013, respectively	9,948	13,514
Receivables from related parties, net of allowance for doubtful accounts of $0 for both dates	3,522	2,716
Prepaid insurance	1,237	3,482
Assets held for sale	281	—
Other current assets	1,822	1,821
Total current assets	19,987	26,381
Property, plant and equipment, net of accumulated depreciation of $153,216 and $164,094 at December 31, 2012 and June 30, 2013, respectively	267,741	290,124
Investment in unconsolidated affiliate	—	16,827
Goodwill	7,216	7,216
Debt issuance costs, net	3,225	3,882
Intangibles and other assets, net	1,656	1,474
Total assets	$299,825	$345,904
LIABILITIES AND PARTNERS’ CAPITAL		
Current liabilities:		
Accounts payable	$10,052	$10,918
Accrued interest payable	164	66
Accrued interest payable to related parties	304	—
Accrued property taxes payable	1,938	2,016
Unearned revenue	4,068	4,584
Unearned revenue with related parties	316	261
Accrued payroll	6,409	5,067
Other current liabilities	4,032	5,036
Current portion of long-term payable to related parties	1,881	—
Total current liabilities	29,164	27,948
Long-term payable to related parties	800	—
Other long-term liabilities	206	128
Long-term debt (including $15.0 million with related parties at December 31, 2012)	211,000	262,411
Commitments and contingencies (Note 13)		
Partners’ capital:		
Series A Preferred Units (30,159,958 units issued and outstanding for both dates)	204,599	204,599

Common unitholders (22,675,135 and 22,682,702 units issued and outstanding at December 31, 2012 and June 30, 2013, respectively)	464,433	461,191
General partner interest (2.1% with 1,127,755 general partner units outstanding for both dates)	(610,377)	(610,373)
Total Partners’ capital	58,655	55,417
Total liabilities and Partners’ capital	$299,825	$345,904

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

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

	Three Months ended June 30,		Six Months ended June 30,	
	2012	2013	2012	2013
	(unaudited)			
Service revenue:				
Third party revenue	$32,912	$34,794	$66,046	$67,899
Related party revenue	10,846	11,504	22,288	23,983
Total revenue	43,758	46,298	88,334	91,882
Expenses:				
Operating	30,518	32,093	59,806	63,905
General and administrative	4,386	4,490	9,489	9,157
Total expenses	34,904	36,583	69,295	73,062
Gain on sale of assets	263	1,220	5,219	998
Operating income	9,117	10,935	24,258	19,818
Other income (expense):				
Equity earnings (loss) in unconsolidated affiliate	—	(118)	—	(173)
Interest expense (net of capitalized interest of $35, $456, $63 and $698, respectively)	(2,897)	(4,559)	(5,968)	(7,291)
Income before income taxes	6,220	6,258	18,290	12,354
Provision for income taxes	73	93	149	166
Net income	$6,147	$6,165	$18,141	$12,188
Allocation of net income for calculation of earnings per unit:				
General partner interest in net income	$186	$129	$493	$316
Preferred interest in net income	$5,391	$5,391	$10,782	$10,782
Beneficial conversion feature attributable to Preferred Units	$—	$—	$1,853	$—
Income available to limited partners	$570	$645	$5,013	$1,090
Basic and diluted net income per common unit	$0.02	$0.03	$0.22	$0.05
Weighted average common units outstanding - basic and diluted	22,670	22,681	22,665	22,678

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

BLUEKNIGHT ENERGY PARTNERS, L.P.
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, 2012	$464,433	$204,599	$(610,377)	$58,655
Net income	1,151	10,782	255	12,188
Equity-based incentive compensation	997	—	21	1,018
Profits interest contribution	—	—	74	74
Distributions	(5,390)	(10,782)	(346)	(16,518)
Balance, June 30, 2013	$461,191	$204,599	$(610,373)	$55,417

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

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

	Six Months ended June 30,	
	2012	2013
	(unaudited)	
Cash flows from operating activities:		
Net income	$18,141	$12,188
Adjustments to reconcile net income to net cash provided by operating activities:		
Provision for uncollectible receivables from third parties	—	(397)
Depreciation and amortization	11,382	11,734
Amortization and write-off of debt issuance costs	888	2,932
Asset impairment charge	1,073	—
Gain on sale of assets	(5,219)	(998)
Equity-based incentive compensation	667	1,018
Equity (earnings) loss in unconsolidated affiliate	—	173
Changes in assets and liabilities		
Decrease (increase) in accounts receivable	2,555	(2,962)
Decrease in receivables from related parties	1,892	806
Decrease in prepaid insurance	309	500
Increase in other current assets	(1,312)	1
Decrease (increase) in other assets	(1)	30
Decrease in accounts payable	(2,718)	(1,388)
Decrease in accrued interest payable	(18)	(98)
Decrease in accrued interest payable to related parties	(183)	(304)
Increase in accrued property taxes	182	78
Increase in unearned revenue	2,962	516
Increase (decrease) in unearned revenue from related parties	491	(55)
Decrease in accrued payroll	(1,196)	(1,342)
Decrease in other accrued liabilities	(1,188)	(683)
Net cash provided by operating activities	28,707	21,749
Cash flows from investing activities:		
Capital expenditures	(13,179)	(31,952)
Proceeds from sale of assets	7,291	1,178
Investment in unconsolidated affiliate	—	(17,000)
Net cash used in investing activities	(5,888)	(47,774)
Cash flows from financing activities:		
Payment on insurance premium financing agreement	(534)	(1,001)
Debt issuance costs	—	(3,589)
Payments on long-term payable to related party	(790)	(2,681)
Borrowings under credit facility	24,000	314,411
Payments under credit facility	(27,000)	(263,000)
Capital contribution related to profits interest	—	74
Distributions	(15,903)	(16,518)
Net cash provided by (used in) financing activities	(20,227)	27,696
Net increase in cash and cash equivalents	2,592	1,671
Cash and cash equivalents at beginning of period	1,239	3,177
Cash and cash equivalents at end of period	$3,831	$4,848

Supplemental disclosure of cash flow information:		
Increase (decrease) in accounts payable related to purchase of property, plant and equipment	$(2,898)	$2,254
Increase in accounts receivable due to accrued proceeds on sale of assets	$—	$(207)
Increase in accrued liabilities related to insurance premium financing agreement	$1,580	$2,610

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

BLUEKNIGHT ENERGY PARTNERS, L.P.
NOTES TO UNAUDITED 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) crude oil terminalling and storage services, (ii) crude oil pipeline services, (iii) crude oil trucking and producer field services and (iv) asphalt 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 of 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 and practices generally accepted in the United States of America ("GAAP"). The consolidated statements of operations for the three and six months ended June 30, 2012 and 2013, the consolidated statement of changes in partners' capital for the six months ended June 30, 2013, the statement of cash flows for the six months ended June 30, 2012 and 2013, and the consolidated balance sheet as of June 30, 2013 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 2012 year-end consolidated balance sheet data was derived from audited financial statements but does not include all disclosures required by GAAP. These 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, 2012 filed with the Securities and Exchange Commission (the "SEC") on March 14, 2013 (the "2012 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 2012 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 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 balance sheet. Distributions to the Partnership will reduce the carrying value of its investment and will be reflected in the Partnership's 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 Consolidated Statements of Cash Flows in investing activities. The Partnership evaluates its equity investment for impairment in accordance with FASB guidance with respect to the equity method of accounting for investments in common stock. An impairment of an equity investment results when factors indicate that the investment's fair value is less than its carrying value and the reduction in value is other than temporary in nature.

3. RECENT EVENTS

On February 4, 2013, the Partnership announced that it entered into an agreement with Advantage Pipeline to acquire approximately 30% ownership in a 70 mile crude oil pipeline project running from Pecos, Texas to Crane, Texas (the “Pecos River Pipeline”). The Pecos River Pipeline is a new 16" diameter pipeline that will enable west Texas producers to deliver crude oil to Gulf Coast markets through a pipeline connection at Crane, Texas. The Partnership will operate the pipeline under a long term agreement with Advantage Pipeline (see Note 8).

On June 28, 2013, the Partnership entered into an amended and restated credit agreement which consists of a $400.0 million revolving loan facility (see Note 5).

4. PROPERTY, PLANT AND EQUIPMENT

	Estimated Useful Lives (Years)	December 31, 2012	June 30, 2013
		(dollars in thousands)	
Land	N/A	$16,405	$16,480
Land improvements	10-20	6,287	6,312
Pipelines and facilities	5-30	101,392	105,184
Storage and terminal facilities	10-35	232,102	234,541
Transportation equipment	3-10	18,003	18,570
Office property and equipment and other	3-20	26,009	26,867
Pipeline linefill and tank bottoms	N/A	5,993	5,993
Construction-in-progress	N/A	14,766	40,271
Property, plant and equipment, gross		420,957	454,218
Accumulated depreciation		(153,216)	(164,094)
Property, plant and equipment, net		$267,741	$290,124

Depreciation expense for the three months ended June 30, 2012 and 2013 was $5.7 million and $5.9 million, respectively, and depreciation expense for the six months ended June 30, 2012 and 2013 was $11.3 million and $11.7 million, respectively. In the three and six months ended June 30, 2012, the Partnership recorded asset impairment expense of $1.1 million related to its pipelines and facilities.

5. DEBT

On June 28, 2013, the Partnership entered into an amended and restated credit agreement which consists of a $400.0 million revolving loan facility. Approximately $262.4 million was drawn on the closing date. As of August 2, 2013, approximately $258.4 million of revolver borrowings and $0.5 million of letters of credit were outstanding under the credit facility, leaving the Partnership with approximately $141.1 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. In connection with entering into the amended and restated credit agreement, the Partnership paid certain upfront fees to the lenders thereunder, and the Partnership paid certain arrangement and other fees to the arranger and administrative agent of the credit agreement. The proceeds of loans made under the 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.

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, including all material pipeline, gathering and processing assets, all material storage tanks and asphalt facilities, all material working capital assets and a pledge of all of the Partnership's equity interests in its subsidiaries.

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%) plus an applicable margin that ranges from 1.0% to 2.0%. The Partnership pays a per annum fee on all letters of credit issued under the credit agreement, which fee equals the applicable margin for loans accruing interest based on the eurodollar rate, and the Partnership pays a commitment fee ranging from 0.375% to 0.5% on the unused commitments under the credit agreement. The credit agreement does not have a floor for the alternate base rate or the eurodollar rate. The applicable margins for the Partnership's interest rate, the letter of credit fee and the commitment fee vary quarterly based on the Partnership's consolidated total leverage ratio (as defined in the credit agreement, being generally computed as the ratio of consolidated total debt to consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges).

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

The maximum permitted consolidated total leverage ratio is 4.50 to 1.00, provided that the maximum consolidated total leverage ratio is 5.00 to 1.00 from and after (i) the last day of the fiscal quarter immediately preceding the fiscal quarter in which a specified acquisition (as defined in the credit agreement) occurs to and including the last day of the second full fiscal quarter following the fiscal quarter in which such specified acquisition occurred and (ii) the date on which the Partnership issues qualified senior notes (as defined in the credit agreement, but generally being unsecured indebtedness with no required principal payments prior to June 28, 2019) in an aggregate principal amount (when combined with all other qualified senior notes previously or concurrently issued) that equals or exceeds $200.0 million.

The 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 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, 2013, the Partnership's consolidated total leverage ratio was 4.00 to 1.00 and the consolidated interest coverage ratio was 6.30 to 1.00. The Partnership was in compliance with all covenants of its credit agreement as of June 30, 2013.

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 affect 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 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 7 for additional information regarding distributions.

Each of the following is an event of default under the credit agreement:

- failure to pay any principal, interest, fees, expenses or other amounts when due;
- failure to meet the quarterly financial covenants;
- failure to observe any other agreement, obligation or covenant in the new credit agreement or any related loan document, subject to cure periods for certain failures;
- the failure of any representation or warranty to be materially true and correct when made;
- the Partnership's, or any of its restricted subsidiaries,' default under other indebtedness that exceeds a threshold amount;
- judgments against the Partnership or any of its restricted subsidiaries, in excess of a threshold amount;
- certain ERISA events involving the Partnership or its restricted subsidiaries resulting in a material adverse effect on the Partnership;
- bankruptcy or other insolvency events involving the Partnership or any of its restricted subsidiaries; and
- a change of control (as defined in the credit agreement, but generally being (i) the General Partner ceasing to own 100% of the Partnership's general partner interest or ceasing to control the Partnership, or (ii) Vitol Holding B.V. (together with its affiliates, "Vitol") and Charlesbank Capital Partners, LLC ceasing 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, all indebtedness under the credit agreement will immediately become due and payable. If any other event of default exists under the credit agreement, the lenders may accelerate the maturity of the obligations outstanding under the credit agreement and exercise other rights and remedies. In addition, if any event of default exists under the credit agreement, the lenders may commence foreclosure or other actions against the collateral.

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

Upon the execution of the amended and restated credit agreement, the Partnership expensed $1.8 million of debt issuance costs related to the extinguished term loan, and the Partnership expensed $0.2 million in debt issuance costs related to its revolving loan facility, leaving a remaining balance of $0.5 million ascribed to those lenders with commitments under both the prior and the amended and restated credit facility. During the six months ended June 30, 2013, the Partnership capitalized debt issuance costs of $0.2 million related to the prior credit facility and $3.4 million related to the current credit facility. The Partnership did not incur any debt issuance costs in the six months ended June 30, 2012. The 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 the three months ended June 30, 2012 and 2013 was $0.4 million and $0.5 million, respectively, and for each of the six months ended June 30, 2012 and 2013 was $0.9 million.

During the three months ended June 30, 2012 and 2013, the weighted average interest rate under the Partnership's credit agreement, excluding the $2.0 million of debt issuance costs related to the prior credit facility that was expensed in the three months ended June 30, 2013, was 5.17% and 5.05%, respectively, resulting in interest expense of approximately $2.8 million and $3.2 million, respectively. During the six months ended June 30, 2012 and 2013, the weighted average interest rate under the Partnership's credit agreement, excluding the $2.0 million of debt issuance costs related to the prior credit facility that was expensed in the six months ended June 30, 2013 was 5.29% and 5.09%, respectively resulting in interest expense of approximately $5.7 million and $6.1 million, respectively. As of June 30, 2013, borrowings under the Partnership's amended and restated credit agreement bore interest at a weighted average interest rate of 3.29%.

During the three months ended June 30, 2012 and 2013, the Partnership capitalized interest of less than $0.1 million and $0.5 million, respectively. During the six months ended June 30, 2012 and 2013, the Partnership capitalized interest of $0.1 million and $0.7 million, respectively.

6. 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 entities' general partner based on the general partner's ownership interest at the time. The following sets forth the computation of basic and diluted net income per common unit (in thousands, except per unit data):

	Three Months ended June 30,		Six Months ended June 30,	
	2012	2013	2012	2013
Net income	$6,147	$6,165	$18,141	$12,188
General partner interest in net income	186	129	493	316
Preferred interest in net income	5,391	5,391	10,782	10,782
Beneficial conversion feature attributable to preferred units	—	—	1,853	—
Income available to limited partners	$570	$645	$5,013	$1,090
Basic and diluted weighted average number of units:				
Common units	22,670	22,681	22,665	22,678
Restricted and phantom units	633	737	516	651
Basic and diluted net income per common unit	$0.02	$0.03	$0.22	$0.05

7. DISTRIBUTIONS

On July 22, 2013, the Board of Directors of the General Partner (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, 2013. The Partnership will pay this distribution on the preferred units on August 14, 2013 to unitholders of record as of August 2, 2013.

In addition, the Board declared a cash distribution of $0.12 per unit on its outstanding common units, a 2.1% increase over the previous quarter's distribution. The distribution will be paid on August 14, 2013 to unitholders of record on August 2, 2013. The distribution is for the three months ended June 30, 2013. The total distribution will be approximately $2.9 million, with approximately $2.7 million and less than $0.1 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.

8. RELATED PARTY TRANSACTIONS

The Partnership provides crude oil gathering, transportation, terminalling and storage services to Vitol. For the three months ended June 30, 2012 and 2013, the Partnership recognized revenues of $10.8 million and $11.4 million, respectively, for services provided to Vitol. For the six months ended June 30, 2012 and 2013, the Partnership recognized revenues of $22.3 million and $23.9 million, respectively, for services provided to Vitol. As of December 31, 2012 and June 30, 2013, the Partnership had receivables from Vitol of $3.1 million and $2.3 million, respectively.

The Partnership also provides operating and administrative services to Advantage Pipeline. For the three and six months ended June 30, 2013, the Partnership recognized revenues of $0.1 million for services provided to Advantage Pipeline.

The Partnership also had a receivable from its General Partner of $0.5 million as of both December 31, 2012 and June 30, 2013.

Vitol Omnibus Agreement

On February 15, 2010, the Partnership entered into an Omnibus Agreement (the "Vitol Omnibus Agreement") with Vitol. Pursuant to the Vitol Omnibus Agreement, the Partnership agreed to provide certain of its employees, consultants and agents (the “Designated Persons”) to Vitol for use by Vitol’s crude oil marketing division. In return, Vitol agreed to reimburse the Partnership in an amount equal to (i) the wages, salaries, bonuses, make whole payments, payroll taxes and the cost of all employee benefits of each Designated Person, in each case as adjusted to properly reflect the time spent by such Designated Person in the performance services for Vitol, (ii) all direct expenses, including, without limitation, any travel and entertainment expenses, incurred by each Designated Person in connection with such Designated Person’s provision of services for Vitol, (iii) a monthly charge of $1,500.00 per Designated Person for each Designated Person that performs services for Vitol during any portion of such month, plus (iv) the sum of subsections (i) through (iii) above multiplied by 0.10. In addition, the Vitol Omnibus Agreement provides that if during any month any Designated Person has spent more than 80% of his time performing services for Vitol, then Vitol will have the right for the succeeding three months to request that such individual be transitioned directly to the employment of Vitol. The Vitol Omnibus Agreement was reviewed and approved by the Board's conflicts committee in accordance with the Partnership's procedures for approval of related party transactions and the provisions of the Partnership's partnership agreement. During the six months ended June 30, 2012 the Partnership received payments of $0.1 million pursuant to the Vitol Omnibus Agreement. The Partnership and Vitol terminated the Vitol Omnibus Agreement on March 27, 2012.

Vitol Storage Agreements

In connection with the Partnership's acquisition of certain of its crude oil storage assets from SemGroup Corporation ("SemCorp") in May 2008, the Partnership was assigned from SemCorp a storage agreement with Vitol under which the Partnership provided crude oil storage services to Vitol (the "2008 Vitol Storage Agreement"). The initial term of the 2008 Vitol Storage Agreement was from June 1, 2008 through June 30, 2010. This agreement was amended in 2010 to extend the term of the agreement until June 1, 2011 and again in 2011 to extend the term of the agreement to June 1, 2012. Because Vitol was a third party (and not a related or affiliated party) at the time of entering into the 2008 Vitol Storage Agreement, such agreement was not approved by the Board or the Board's conflicts committee in accordance with the Partnership's procedures for approval of related party transactions. Vitol became a related party when it acquired the General Partner in November 2009 (the "Vitol Change of Control"). Since the amendments occurred subsequent to the Vitol Change of Control, they were reviewed and approved by the Board's conflicts committee in accordance with the Partnership's procedures for approval of related party transactions and the provisions of the partnership agreement. The Partnership earned revenues of approximately $2.2 million and $5.5 million from Vitol with respect to services provided pursuant to the 2008 Vitol Storage Agreement for the three and six months ended June 30, 2012, respectively. The 2008 Vitol Storage Agreement expired according to its terms on June 1, 2012. The Partnership believes that the rates it charged Vitol under the 2008 Vitol Storage Agreement were fair and reasonable to the Partnership and its unitholders and were comparable with the rates the Partnership charged third parties.

In March 2010, the Partnership entered into a second crude oil storage services agreement with Vitol under which the Partnership began providing additional crude oil storage services to Vitol effective May 1, 2010 (the "2010 Vitol Storage Agreement"). The initial term of the 2010 Vitol Storage Agreement is five years commencing on May 1, 2010, subject to automatic renewal periods for successive one year periods until terminated by either party with ninety days prior notice. The 2010 Vitol Storage Agreement was reviewed and approved by the Board's conflicts committee in accordance with the Partnership's procedures for approval of related party transactions and the provisions of the partnership agreement. Service revenues under the 2010 Vitol Storage Agreement are based on the 2.0 million barrels of storage capacity of the crude oil storage tanks that are dedicated to Vitol under the agreement. The Partnership generated revenues under this agreement of approximately $2.9 million and $2.2 million during the three months ended June 30, 2012 and 2013, respectively. The Partnership generated revenues under this agreement of approximately $5.9 million and $4.7 million during the six months ended June 30, 2012 and 2013, respectively. In March 2013, the 2010 Vitol Storage Agreement was amended to adjust the rates the Partnership charges Vitol for services provided under the agreement. The Partnership believes that the rates it charges Vitol under the 2010 Vitol Storage Agreement are fair and reasonable to the Partnership and its unitholders and are comparable with the rates the Partnership charges third parties.

In 2012, The Partnership entered into three new crude oil storage services agreements with Vitol, the "2012 Vitol 12-month Storage Agreement" and the "2012 Vitol 6-month Storage Agreement," which became effective June 1, 2012, and the "Vitol September 2012 Storage Agreement," which became effective September 1, 2012. The Partnership believes that the rates it charges Vitol under each of these agreements, as amended, are fair and reasonable to the Partnership and its unitholders and are comparable with the rates the Partnership charges third parties. The Board's conflicts committee reviewed and approved each of these agreements and each of the amendments described below in accordance with the Partnership's procedures for approval of related party transactions and the provisions of the partnership agreement.

Service revenues under the 2012 Vitol 12-month Storage Agreement are based on the 1.0 million barrels of storage capacity of the crude oil storage tanks that are dedicated to Vitol under the agreement. The initial term of the 2012 Vitol 12-month Storage Agreement was from June 1, 2012 through May 31, 2013. In March 2013, the 2012 Vitol 12-month Storage Agreement was amended to extend the term through March 31, 2014 and to adjust the rates the Partnership charges Vitol for services provided under the agreement. The Partnership generated revenues under this agreement of approximately $0.5 million for both the three and six months ended June 30, 2012. The Partnership generated revenues under this agreement of approximately $1.0 million and $2.3 million for the three and six months ended June 30, 2013, respectively.

Service revenues under the 2012 Vitol 6-month Storage Agreement are based on the 0.5 million barrels of storage capacity of the crude oil storage tanks that are dedicated to Vitol under the agreement. The initial term of the 2012 Vitol 6-month Storage Agreement was from June 1, 2012 through November 30, 2012. Upon expiration of the initial term, this agreement became subject to a rolling 90 day cancellation notice. In March 2013, the 2012 Vitol 6-month Storage Agreement was amended to extend the term through October 31, 2013 and to adjust the rates the Partnership charges Vitol for services provided under the agreement. The Partnership generated revenues under this agreement of approximately $0.2 million for both the three and six months ended June 30, 2012. The Partnership generated revenues under this agreement of approximately $0.5 million and $1.1 million for the three and six months ended June 30, 2013, respectively.

Service revenues under the Vitol September 2012 Storage Agreement are based on the 0.5 million barrels of storage capacity of the crude oil storage tanks that are dedicated to Vitol under the agreement. The initial term of the Vitol September 2012 Storage Agreement was from September 1, 2012 to February 28, 2013. In March 2013, the Vitol September 2012 Storage Agreement was amended to extend the term through October 31, 2013 and to adjust the rates the Partnership charges Vitol for services provided under the agreement. The Partnership generated revenues under this agreement of approximately$0.5 million and $1.1 million for the three and six months ended June 30, 2013, respectively.

Vitol Throughput Capacity Agreement

In August 2010, the Partnership and Vitol entered into a Throughput Capacity Agreement (the "ENPS Throughput Agreement"). Pursuant to the ENPS Throughput Agreement, Vitol purchased 100% of the throughput capacity on the Partnership's Eagle North Pipeline System ("ENPS"). The Partnership put ENPS in service in December 2010. In September 2010, Vitol paid the Partnership a prepaid fee equal to $5.5 million, and Vitol agreed to pay additional usage fees for every barrel delivered by or on behalf of Vitol on ENPS. This $5.5 million fee received from Vitol was accounted for as a long-term payable to a related party. In addition, if the payments made by Vitol in any contract year under the ENPS Throughput Agreement were in the aggregate less than $2.4 million, then Vitol was obligated to pay the Partnership a deficiency payment equal to $2.4 million minus the aggregate amount of all payments made by Vitol during such contract year. In March 2012, the Partnership received a deficiency payment of $0.3 million from Vitol in relation to the 2011 contract year. In February 2013, the Partnership received a deficiency payment of $0.2 million from Vitol in relation to the 2012 contract year. The ENPS Throughput Agreement was approved by the Board's conflicts committee in accordance with the Partnership's procedures for approval of related party transactions and the provisions of its partnership agreement.

During the three months ended June 30, 2012 and 2013, the Partnership incurred interest expense under this agreement of approximately $0.1 million and less than $0.1 million, respectively. During the six months ended June 30, 2012 and 2013, the Partnership incurred interest expense under this agreement of approximately $0.3 million and $0.1 million, respectively. The agreement had an effective annual interest rate of 14.1%. In April 2013, the Partnership repurchased 100% of the throughput capacity on ENPS from Vitol for $2.5 million, and the ENPS Throughput Agreement was terminated.

Vitol Operating and Maintenance Agreement

In August 2011, the Partnership and Vitol entered into an operating and maintenance agreement (the "Vitol O&M Agreement") relating to the operation and maintenance of Vitol's crude oil terminal located in Midland, Texas (the "Midland Terminal"). Pursuant to the Vitol O&M Agreement, the Partnership provides certain operating and maintenance services with respect to the Midland Terminal. The term of the Vitol O&M Agreement commenced on September 1, 2012 and will continue for five years. During the three and six months ended June 30, 2013, the Partnership generated revenues of $0.2 million and $0.3 million, respectively, under the Vitol O&M Agreement. The Partnership believes that the rates it charges Vitol under the Vitol O&M Agreement are fair and reasonable to the Partnership and its unitholders and are comparable with the rates the Partnership charges third parties. The Board's conflicts committee reviewed and approved the Vitol O&M Agreement in accordance with the Partnership's procedures for approval of related party transactions and the provisions of the partnership agreement.

Vitol Shared Services Agreement

In August 2012, the Partnership and Vitol entered into a shared services agreement (the "Vitol Shared Services Agreement") pursuant to which the Partnership provides Vitol certain strategic assessment, economic evaluation and project design services. The original term of the Vitol Shared Services Agreement commenced on August 1, 2012 and continued for one year. In August 2013, the term of the Vitol Shared Services Agreement was automatically renewed for one year. The Vitol Shared Services Agreement renews annually unless terminated by either party as provided in the agreement. During the three and six months ended June 30, 2013, the Partnership generated revenues of less than $0.1 million and $0.1 million, respectively, under the Vitol Shared Services Agreement. The Partnership believes that the rates it charges Vitol under the Vitol Shared Services Agreement are fair and reasonable to the Partnership and its unitholders. The Board's conflicts committee reviewed and approved the Vitol Shared Services Agreement in accordance with the Partnership's procedures for approval of related party transactions and the provisions of the partnership agreement.

Vitol's Commitment under the Partnership's Credit Agreement

Vitol was a lender under the Partnership's prior credit agreement and committed to loan the Partnership $15.0 million pursuant to such agreement. During the three and six months ended June 30, 2013, Vitol received its pro rata portion of the interest payments in connection with being a lender under the credit agreement and received approximately $0.2 million and $0.3 million in connection therewith. During the three and six months ended June 30, 2012, Vitol received interest payments of approximately $0.2 million and $0.3 million, respectively. Vitol is not a lender under the Partnership's amended and restated credit agreement.

Advantage Pipeline Operating and Administrative Services Agreement

In January 2013, the Partnership and Advantage Pipeline entered into an operating and administrative services agreement (the "Advantage O&A Services Agreement") pursuant to which the Partnership will operate Advantage Pipeline's Pecos River Pipeline in west Texas. Under the Advantage O&A Services Agreement, the Partnership will also provide certain administrative services to Advantage Pipeline. The initial term of the Advantage O&A Services Agreement commenced on January 31, 2013 and shall continue for ten years, with the Partnership and Advantage Pipeline each having an option to extend the term for an additional five years. During the three and six months ended June 30, 2013, the Partnership earned revenues of $0.1 million under this agreement.

9. 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. The LTIP authorizes the grant of an aggregate of 2.6 million common units deliverable upon vesting. Although other types of awards are contemplated under the LTIP, currently outstanding awards include "phantom" units, which convey the right to receive common units upon vesting, and "restricted" units, which are grants of common units restricted until the time of vesting. Certain of the phantom unit awards also include distribution equivalent rights ("DERs").

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

In each of December 2010, 2011 and 2012, 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 fair value of the restricted units for each of these grants was less than $0.1 million.

In March 2011, 2012 and 2013, grants for 299,900, 353,300 and 251,106 phantom units, respectively, were made, which vest on January 1, 2014, January 1, 2015 and January 1, 2016, 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 $8.25, $6.76 and $8.75 per unit, respectively, which is the closing market price on the grant date of the awards. The value of these award grants was approximately $2.5 million, $2.4 million and $2.2 million, respectively, on their grant date. In June 2013, grants of 1,300 phantom units that will vest on January 1, 2014 and 3,500 units that will vest on January 1, 2015 were made. The weighted average grant date fair-value of the awards is $8.40, which is the closing market price on the grant date. The value of these award grants was $40,320. The unrecognized estimated compensation cost of outstanding phantom units at June 30, 2013 was $2.3 million, which will be recognized over the remaining vesting period. As of June 30, 2013, the Partnership expects approximately 74% of these awards will vest.

In September 2012, Mark Hurley was granted 500,000 phantom units under the LTIP upon his employment as the Chief Executive Officer of the General Partner. These grants 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, 2013 was $2.4 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, 2012 and 2013 was $0.4 million and $0.5 million, respectively, and for the six months ended June 30, 2012 and 2013 was $0.7 million and $1.0 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, 2012	1,016,703	$6.51
Granted	255,906	8.74
Vested	10,373	7.73
Forfeited	34,124	7.60
Nonvested at June 30, 2013	1,228,112	$6.94

10. EMPLOYEE BENEFIT PLAN

Under the Partnership's 401(k) Plan, which was instituted in 2009, employees who meet specified service requirements may contribute a percentage of their total compensation, up to a specified maximum, to the 401(k) Plan. The Partnership may match each employee's contribution, up to a specified maximum, in full or on a partial basis. The Partnership recognized expense of $0.3 million and $0.4 million for the three months ended June 30, 2012 and 2013, respectively, for discretionary contributions under the 401(k) Plan. The Partnership recognized expense of $0.6 million and $0.7 million for the six months ended June 30, 2012 and 2013, respectively, 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 $0.3 million for the three months ended June 30, 2012 and 2013, respectively, for discretionary profit sharing contributions under the 401(k) Plan. The Partnership recognized expense of $0.5 million for each of the six months ended June 30, 2012 and 2013, respectively, for discretionary profit sharing contributions under the 401(k) Plan.

11. 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.

The Partnership had no recurring financial assets or liabilities subject to fair value measurements as of December 31, 2012 or June 30, 2013.

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, 2013, the carrying values on the 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, 2013 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.

12. OPERATING SEGMENTS

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

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 Longview system and ENPS, 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 Longview system. The Partnership refers to its third system, originating in Cushing, Oklahoma and terminating in Ardmore, Oklahoma, as ENPS.

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.

ASPHALT SERVICES —The Partnership provides asphalt product and residual fuel terminalling, storage and blending services at its 44 terminalling and storage facilities located in twenty-two states.

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

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

	Crude Oil Terminalling and Storage Services	Crude Oil Pipeline Services	Crude Oil Trucking and Producer Field Services	Asphalt Services	Total
Three months ended June 30, 2012					
Service revenue					
Third party revenue	$3,087	$3,594	$11,702	$14,529	$32,912
Related party revenue	6,293	1,180	3,340	33	10,846
Total revenue for reportable segments	9,380	4,774	15,042	14,562	43,758
Operating expenses (excluding depreciation and amortization)	1,015	4,902	13,268	5,607	24,792
Operating margin (excluding depreciation and amortization)	8,365	(128)	1,774	8,955	18,966
Total assets (end of period)	68,837	96,542	20,450	114,521	300,350
Three months ended June 30, 2013					
Service revenue					
Third party revenue	$3,066	$3,360	$12,356	$16,012	$34,794
Related party revenue	4,580	1,139	5,256	529	11,504
Total revenue for reportable segments	7,646	4,499	17,612	16,541	46,298
Operating expenses (excluding depreciation and amortization)	988	3,556	15,022	6,615	26,181
Operating margin (excluding depreciation and amortization)(1)	6,658	943	2,590	9,926	20,117
Total assets (end of period)	66,884	149,321	21,204	108,495	345,904
Six months ended June 30, 2012					
Service revenue					
Third party revenue	$5,731	$8,059	$24,480	$27,776	$66,046
Related party revenue	12,894	2,510	6,559	325	22,288
Total revenue for reportable segments	18,625	10,569	31,039	28,101	88,334
Operating expenses (excluding depreciation and amortization)	1,725	8,850	26,368	11,481	48,424
Operating margin (excluding depreciation and amortization)(1)	16,900	1,719	4,671	16,620	39,910
Total assets (end of period)	68,837	96,542	20,450	114,521	300,350
Six months ended June, 2013					
Service revenue					
Third party revenue	$5,933	$7,522	$24,373	$30,071	$67,899
Related party revenue	10,018	2,372	10,565	1,028	23,983
Total revenue for reportable segments	15,951	9,894	34,938	31,099	91,882
Operating expenses (excluding depreciation and amortization)	1,804	7,495	30,244	12,628	52,171
Operating margin (excluding depreciation and amortization)(1)	14,147	2,399	4,694	18,471	39,711
Total assets (end of period)	66,884	149,321	21,204	108,495	345,904

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

	Three Months ended June 30,		Six Months ended June 30,	
	2012	2013	2012	2013
Operating margin (excluding depreciation and amortization)	$18,966	$20,117	$39,910	$39,711
Depreciation and amortization	(5,726)	(5,912)	(11,382)	(11,734)
General and administrative expenses	(4,386)	(4,490)	(9,489)	(9,157)
Gain on sale of assets	263	1,220	5,219	998
Interest expense	(2,897)	(4,559)	(5,968)	(7,291)
Equity earnings (loss) in unconsolidated entity	$—	$(118)	$—	$(173)
Income before income taxes	$6,220	$6,258	$18,290	$12,354

13. 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 SemCorp in connection with the Partnership's initial public offering in 2007. Keystone seeks to quiet title to the specified 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 parties are engaged in discovery. The Partnership intends to vigorously defend these claims. No trial date has been set by the court.

In March and April 2009, nine current or former executives (the "Claimants") of SemCorp and certain of its affiliates filed wage claims with the Oklahoma Department of Labor against the General Partner. Their claims arise from the General Partner's Long-Term Incentive Plan, Employee Phantom Unit Agreement ("Phantom Unit Agreement"). Most claimants alleged that phantom units previously awarded to them vested upon the change of control that occurred in July 2008. One claimant alleged that his phantom units vested upon his termination. The claimants contended the General Partner's failure to deliver certificates for the phantom units within 60 days after vesting caused them to be damaged, and they sought recovery of approximately $2.0 million in damages and penalties. On April 30, 2009, all of the wage claims were dismissed on jurisdictional grounds by the Oklahoma Department of Labor.

On July 8, 2009, the Claimants filed suit against the General Partner in Tulsa County District Court claiming they are entitled to recover the value of phantom units purportedly due them under the Phantom Unit Agreement. The claimants asserted claims against the General Partner for alleged failure to pay wages and breach of contract and sought to recover the alleged value of units in the total amount of approximately $1.3 million, plus additional damages and attorneys' fees. After the suit was filed, the Partnership distributed phantom units to certain of the claimants. On April 14, 2010, a Tulsa County District Court judge ruled in favor of seven of the claimants and awarded them approximately $1.0 million in damages. The Partnership appealed this ruling. On October 22, 2010, the General Partner was ordered to pay $0.2 million in attorneys' fees. The Partnership also appealed this order.

On December 20, 2012, the Oklahoma Court of Civil Appeals issued its opinion on the appeals filed by the Partnership. The appellate court determined the phantom unit awards were not wages under the applicable statute, but affirmed the trial court's decision as to a breach of contract of the Phantom Unit Agreement by the General Partner. The appellate court remanded the case for a hearing to determine the amount of damages and attorneys' fees to which claimants were entitled based on the breach of contract. The Partnership filed a petition for rehearing asserting the trial court must take mitigation into account when calculating the breach of contract damages and that a prevailing party attorneys' fee is not available under the controlling Oklahoma statute. On June 12, 2013, the Oklahoma Court of Civil Appeals issued its opinion on the appeals the Partnership filed. The appellate court opined that the Partnership did not meet its burden of proof of introducing evidence establishing some or all of the claimants' damagers were avoidable. The appellate court also determined that the plaintiffs are not entitled to a recovery of attorney's fees and costs. The appellate court remanded the case for a hearing to determine the amount of damages to which claimants were entitled based on the breach of contract. Cross-motions were filed in the appellate court seeking attorney's fees and costs incurred during the pendency of the appeal. On July 12, 2013, the appellate court determined that the Partnership is not entitled to a recovery of attorney's fees and costs. While ultimate resolution of the matter cannot be determined, the Partnership believes that it will not have a material adverse effect on the Partnership's financial condition or results of operations.

On February 13, 2013, the Partnership filed suit against Koch Industries, Inc. (together with its subsidiaries, "Koch"), a previous owner of the Partnership's asphalt facility located in Northumberland, Pennsylvania. The suit was filed in the United States District Court for the Middle District of Pennsylvania. The Partnership is seeking a declaration that Koch is responsible for any assessment and cleanup costs related to certain environmental liabilities. Koch has previously taken the position that the Partnership has the responsibility to assess the polychlorinated biphenyl contamination at such facility although the contamination occurred prior to the Partnership becoming the owner of such facility. The Partnership intends to vigorously pursue the litigation.

On July 11, 2011, ExxonMobil filed suit against the Partnership in Harris County District Court, State of Texas, requesting damages in excess of $35,000 from the Partnership and other, third party service providers in connection with the relocation of existing pipelines of ExxonMobil and the Partnership. The Partnership has filed its answer to the claims and asserted cross-claims against third party service providers including the subcontractors of ExxonMobil. ExxonMobil had previously sent a settlement demand seeking approximately $1.9 million in damages. The Partnership filed a motion for summary judgment against these claims. On May 31, 2013, the District Court of Harris County, State of Texas issued an order granting summary judgment in favor of the Partnership on all claims filed by ExxonMobil. No further matters are pending regarding this legal action.

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 is contesting 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 District Court of Tulsa County, and on June 25, 2013, the Partnership filed a notice of non-objection and motion to adopt the special master's report. The Partnership intends to seek additional damages from SemCorp related to various injuries to the Partnership as a result of SemCorp's failure to resolve this issue. No trial date is set.

On July 13, 2012, the Partnership and one of its employees were named in a motor vehicle negligence suit in the District Court of Woodward County, Oklahoma, arising out of an accident involving one of the Partnership's crude oil tanker trucks. The accident resulted in the death of one of the occupants of the other vehicle, and injuries to the other occupant. The plaintiff is seeking damages in excess of $75,000 from the Partnership. The Partnership has submitted the claim to its insurance carriers, and the Partnership believes that any recovery would be within applicable policy limits after payment of its $100,000 deductible. Although it is not possible to predict the ultimate outcome of this matter, the Partnership does not expect that an award in this matter will have a material adverse impact on its consolidated results of operations or financial condition.

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.

14. INCOME TAXES

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

If the Partnership were treated as a corporation for federal income tax purposes, then it would pay federal income tax on its income at the 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 common units.

The Partnership has entered into storage contracts and leases with third party customers with respect to substantially all of its asphalt facilities. At the time of entering into such agreements, it was unclear under current tax law as to whether the rental income from the leases, and the fees attributable to certain of the processing services the Partnership provides under certain of the storage contracts, constitute "qualifying income." In the second quarter of 2009, the Partnership submitted a request for a ruling from the IRS that rental income from the leases constitutes "qualifying income." In October 2009, the Partnership received a favorable ruling from the IRS. As part of this ruling, however, the Partnership agreed to transfer, and has transferred, certain of its asphalt processing assets and related fee income to a subsidiary taxed as a corporation. This transfer occurred in the first quarter of 2010. Such subsidiary is required to pay federal income tax on its income at the corporate tax rate, which is currently a maximum of 35%, and will likely pay state (and possibly local) income tax at varying rates. Distributions from this subsidiary will generally be taxed again to unitholders as corporate distributions and none of the income, gains, losses, deductions or credits of this subsidiary will flow through to the Partnership's unitholders.

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, 2013 are presented below (dollars in thousands):

Deferred tax assets	
Difference in bases of property, plant and equipment	$1,043
Deferred tax asset	1,043
Less: valuation allowance	(1,043)
Net deferred tax asset	$—

Given that the Partnership's subsidiary that is taxed as a corporation has a limited earnings history for purposes of determining the likelihood of realizing the benefits of the deferred tax assets, the Partnership has provided a full valuation allowance against its deferred tax asset.

15. RECENTLY ISSUED ACCOUNTING STANDARDS

In July 2012, the FASB issued ASU 2012-02, "Testing Indefinite-Lived Intangible Assets for Impairment," which allows an entity to first assess qualitative factors to determine whether it is necessary to perform a quantitative impairment test. Under these amendments, an entity would not be required to calculate the fair value of an indefinite-lived intangible asset unless the entity determines, based on qualitative assessment, that it is not more likely than not that the indefinite-lived intangible asset is impaired. The amendments include a number of events and circumstances for an entity to consider in conducting the qualitative assessment. The Partnership adopted this guidance beginning in its December 31, 2012 annual impairment test, and the impact was not material.

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. (f/k/a SemGroup 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, 2012, which was filed with the Securities and Exchange Commission (the "SEC") on March 14, 2013 (the "2012 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 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 2012 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) crude oil terminalling and storage services, (ii) crude oil pipeline services, (iii) crude oil trucking and producer field services, and (iv) asphalt services.

Recent Events

In February 2013, we entered into an agreement with Advantage Pipeline, L.L.C. (“Advantage Pipeline”) to acquire approximately 30% ownership in a 70 mile crude oil pipeline project running from Pecos, Texas to Crane, Texas (the “Pecos River Pipeline”). The Pecos River Pipeline is a new 16" diameter pipeline that will enable west Texas producers to deliver crude oil to Gulf Coast markets through a pipeline connection at Crane, Texas. We will operate the pipeline under a long term agreement with Advantage Pipeline.

On June 28, 2013, the Partnership entered into an amended and restated credit agreement which consists of a $400.0 million revolving loan facility. Approximately $262.4 million was drawn on the closing date. The amended and restated 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 amended and restated credit agreement.

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 and six months ended June 30, 2013, we derived approximately 25% and 26%, respectively, of our revenues from services we provided to Vitol, with the remainder of our services being provided to third parties.

Our revenues increased by $2.5 million, or 6%, for the three months ended June 30, 2013 as compared to the three months ended June 30, 2012. Our revenues increased by $3.6 million, or 4%, for the six months ended June 30, 2013 as compared to the six months ended June 30, 2012. This increase is primarily attributed to higher volumes of crude oil transported by our trucking assets and short-term storage service agreements at certain of our asphalt services facilities.

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) crude oil terminalling and storage services and (ii) asphalt services.

As of August 2, 2013, we had approximately 5.6 million barrels of crude oil storage under service contracts with remaining terms ranging from month-to-month to 21 months, including 4.1 million barrels under contract to Vitol. As of August 2, 2013, 1.4 million barrels of crude oil storage contracts were month-to-month agreements or expire in 2013. We are in negotiations to contract the remaining storage capacity; however, there is no certainty that contracts will be renewed, or, if renewed, 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.

Historically, the majority of our storage contracts have been for relatively short terms consisting of month-to-month or one year or less, and we have been able to contract for higher rates because of the near term expiration and market demand at the Cushing Interchange. Over the past two years we have endeavored to increase the average duration of our contracts and diversify our storage customer base which has led to decreased average storage rates in return for increased average duration. Additionally, there are a number of market dynamics currently taking place at the Cushing Interchange, including the reversal of Seaway pipeline, the construction of the Keystone pipeline and significant production increases in Kansas, Oklahoma and Texas that are creating new supply and demand challenges affecting the market price for West Texas Intermediate crude as compared to other crude types. We expect these market dynamics to continue in the near term in and around the Cushing Interchange and to have a near term impact on storage rates we charge our customers for services provided at the Cushing Interchange.

We have leases and storage agreements with third party customers relating to 43 of our 44 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.

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, 2013, we transported approximately 51,229 barrels per day on our pipelines, a decrease of 17% as compared to the three months ended June 30, 2012. The decreased throughput is primarily on our Eagle North pipeline system and is a result of a refinery turnaround. We anticipate throughput to return to historical averages for the remainder of 2013. Vitol accounted for 30% of volumes transported in the three months ended June 30, 2013.

For the three months ended June 30, 2013, we transported approximately 57,200 barrels per day on our crude transport trucks, an increase of 15% as compared to the three months ended June 30, 2012. Vitol accounted for approximately 42% of volumes transported in the three months ended June 30, 2013.

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 consolidated financial statements, we are required to estimate the federal and state income taxes in each of the jurisdictions in which our subsidiary that is taxed as a corporation operates. This process involves estimating the actual current tax exposure together with assessing temporary differences resulting from differing treatment of items, such as depreciation, for tax and accounting purposes. These differences result in deferred tax assets and liabilities, which are included in our consolidated balance sheet. We must then assess, using all available positive and negative evidence, the likelihood that the deferred tax assets will be recovered from future taxable income. If we believe that recovery is not likely, we must establish a valuation allowance. To the extent we establish a valuation allowance or increase or decrease this allowance in a period, we must include an expense or reduction of expense within the tax provisions in the consolidated statement 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.

Given that our subsidiary that is taxed as a corporation has limited earnings history 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, 2013.

Distributions

The amount of distributions we pay and the decision to make any distribution is determined by 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 22, 2013, 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, 2013. We will pay this distribution on the preferred units on August 14, 2013 to unitholders of record as of August 2, 2013.

In addition, we declared a cash distribution of $0.12 per unit on our outstanding common units, a 2.1% increase over the previous quarter's distribution. The distribution will be paid on August 14, 2013 to unitholders of record on August 2, 2013. The distribution is for the three months ended June 30, 2013. The total distribution to be paid is approximately $2.9 million, with approximately $2.7 million and less than $0.1 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 the our long-term incentive plan.

Vitol Storage Agreements

In March 2010, we entered into a crude oil storage services agreement with Vitol under which we began providing crude oil storage services to Vitol effective May 1, 2010 (the "2010 Vitol Storage Agreement"). The initial term of the 2010 Vitol

Storage Agreement is five years commencing on May 1, 2010, subject to automatic renewal periods for successive one year periods until terminated by either party with ninety days prior notice. In March 2013, the 2010 Vitol Storage Agreement was amended to adjust the rates we charge Vitol for services provided under the agreement. We believe that the rates we charge Vitol under this agreement are fair and reasonable to us and our unitholders and are comparable with the rates we charge third parties. The Board’s conflicts committee reviewed and approved this agreement, including the amendment thereto, in accordance with our procedures for approval of related party transactions and the provisions of the partnership agreement.

On June 1, 2012, the crude oil storage services agreement with Vitol previously entered into in 2008 expired according to its terms. In anticipation of such expiration, we entered into two new crude oil storage services agreements with Vitol under which we began providing additional crude oil storage services to Vitol effective June 1, 2012. Service revenues under the first agreement are based on the 1.0 million barrels of storage capacity of the crude oil storage tanks that are dedicated to Vitol under the agreement. The initial term of the first agreement was from June 1, 2012 through May 31, 2013. In March 2013, this agreement was amended to extend the term through March 31, 2014 and to adjust the rates we charge Vitol for services provided under the agreement. Service revenues under the second agreement are based on the 0.5 million barrels of storage capacity of the crude oil storage tanks that are dedicated to Vitol under the agreement. The initial term of the second agreement was from June 1, 2012 through November 30, 2012 and automatically renewed twice before being amended in March 2013. The amendment extended the term through October 31, 2013 and adjusted the rates we charge Vitol for services provided under the agreement. We believe that the rates we charge Vitol under these agreements are fair and reasonable to us and our unitholders and are comparable with the rates we charge third parties. The Board’s conflicts committee reviewed and approved these agreements, including the amendments thereto, in accordance with our procedures for approval of related party transactions and the provisions of the partnership agreement.

During the third quarter of 2012, we entered into another 6-month storage agreement with Vitol effective September 1, 2012 (the “Vitol September 2012 Storage Agreement”). Service revenues under the Vitol September 2012 Storage Agreement are based on the 0.5 million barrels of storage capacity of the crude oil storage tanks that are dedicated to Vitol under the agreement. The initial term of the Vitol September 2012 Storage Agreement was from September 1, 2012 to February 28, 2013. In March 2013, the Vitol September 2012 Storage Agreement was amended to extend the term through October 31, 2013 and to adjust the rates we charge Vitol for services provided under the agreement. We believe that the rates we charge Vitol under this agreement are fair and reasonable to us and our unitholders and are comparable with the rates we charge third parties. The Board’s conflicts committee reviewed and approved this agreement, including the amendment thereto, in accordance with our procedures for approval of related party transactions and the provisions of the partnership agreement.

Results of Operations

The table below summarizes our financial results for the three and six months ended June 30, 2012 and 2013:

	Three Months ended June 30,		Six Months ended June 30,	
	2012	2013	2012	2013
Service revenues:				
Crude oil terminalling and storage revenues:				
Third party	$3,087	$3,066	$5,731	$5,933
Related party	6,293	4,580	12,894	10,018
Total crude oil terminalling and storage	9,380	7,646	18,625	15,951
Crude oil pipeline services revenues:				
Third party	3,594	3,360	8,059	7,522
Related party	1,180	1,139	2,510	2,372
Total crude oil pipeline services revenues	4,774	4,499	10,569	9,894
Crude oil trucking and producer field services revenues:				
Third party	11,702	12,356	24,480	24,373
Related party	3,340	5,256	6,559	10,565
Total crude oil trucking and producer field services revenues	15,042	17,612	31,039	34,938
Asphalt services revenues:				
Third party	14,529	16,012	27,776	30,071
Related party	33	529	325	1,028
Total asphalt services	14,562	16,541	28,101	31,099
Total revenues	43,758	46,298	88,334	91,882
Operating expenses:				
Crude oil terminalling and storage	2,051	1,834	3,793	3,494
Crude oil pipeline services	6,194	5,023	11,397	10,386
Crude oil trucking and producer field services	13,644	15,508	27,089	31,187
Asphalt services	8,629	9,728	17,527	18,838
Total operating expenses	30,518	32,093	59,806	63,905
General and administrative expenses	4,386	4,490	9,489	9,157
Gain on sale of assets	263	1,220	5,219	998
Operating income	9,117	10,935	24,258	19,818
Other income (expense):				
Equity earnings (loss) in unconsolidated affiliate	—	(118)	—	(173)
Interest expense	(2,897)	(4,559)	(5,968)	(7,291)
Income tax expense	(73)	(93)	(149)	(166)
Net income	$6,147	$6,165	$18,141	$12,188

Three Months Ended June 30, 2013 Compared to the Three Months Ended June 30, 2012

Service revenues. Service revenues include revenues from crude oil terminalling and storage services, crude oil pipeline services, crude oil trucking and producer field services and asphalt services. Service revenues, including reimbursement revenues of $2.1 million and $1.4 million for the three months ended June 30, 2013 and 2012, respectively, for fuel and power, property taxes, and insurance expenses related to the operations of our liquid asphalt facilities, were $46.3 million for the three

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months ended June 30, 2013 compared to $43.8 million for the three months ended June 30, 2012, an increase of $2.5 million, or 6%.

Crude oil terminalling and storage revenue decreased by $1.8 million to $7.6 million for the three months ended June 30, 2013 compared to $9.4 million for the three months ended June 30, 2012. This is primarily due to lower renegotiated storage rates with Vitol.

Crude oil pipeline services revenue decreased by $0.3 million to $4.5 million for the three months ended June 30, 2013 compared to $4.8 million for the three months ended June 30, 2012, primarily due to decreased throughput volumes on our Eagle North pipeline system. The decreased throughput on our Eagle North pipeline system is a result of a refinery turnaround, and we anticipate throughput to return to historical averages for the remainder of 2013.

Crude oil trucking and producer field services revenue increased by $2.6 million to $17.6 million for the three months ended June 30, 2013, compared to $15.0 million for the three months ended June 30, 2012. This increase is primarily the result of higher volumes of crude oil transported by our trucking assets.

Our asphalt services revenue, including reimbursement of fuel and power, property tax and insurance premiums, increased by $1.9 million to $16.5 million for the three months ended June 30, 2013, compared to $14.6 million for the three months ended June 30, 2012. The increase in revenue is primarily the result of increased product throughput at our facilities, short-term storage service agreements at certain of our facilities, and contractual rate escalations. In addition, reimbursement revenues increased by $0.7 million primarily as a result of increased fuel and power costs related to the operation of our facilities.

Operating expenses. Operating expenses were $32.1 million for the three months ended June 30, 2013 compared to $30.5 million for the three months ended June 30, 2012, an increase of $1.6 million, or 5%.

Crude oil terminalling and storage operating expenses decreased by $0.3 million to $1.8 million for the three months ended June 30, 2013 compared to the three months ended June 30, 2012. This decrease is primarily the result of a decrease in depreciation expense. We do not currently anticipate significant variances in operating expenses related to our crude oil terminalling and storage assets for the remainder of 2013.

Our crude oil pipeline services operating expenses decreased by $1.2 million to $5.0 million for the three months ended June 30, 2013 compared to $6.2 million for the three months ended June 30, 2012. This decrease is primarily attributed to the idling of gathering lines associated with our Mid-Continent pipeline system in 2012 and the related $1.0 million impairment loss recorded in the three months ended June 30, 2012.

Our crude oil trucking and producer field services operating expenses increased by $1.9 million to $15.5 million for the three months ended June 30, 2013 compared to $13.6 million for the three months ended June 30, 2012. This increase was primarily driven by the higher volume of crude oil transported by our trucking assets, which resulted in higher driver commissions and fuel and fleet maintenance costs.

Our asphalt operating expenses were $9.7 million for the three months ended June 30, 2013 compared to $8.6 million for the three months ended June 30, 2012, an increase of $1.1 million. This is primarily due to increases in fuel and power costs incurred in connection with the operation of our asphalt facilities.

General and administrative expenses. General and administrative expenses increased by $0.1 million to $4.5 million for the three months ended June 30, 2013 as compared to the three months ended June 30, 2012.

Gain on sale of assets. In the three months ended June 30, 2012, we recognized gains on the sale of assets of $0.3 million. The $1.2 million of gains recorded in the three months ended June 30, 2013 included $0.9 million received from the Texas Department of Transportation to relocate segments of certain of our pipelines.

Interest expense. Interest expense represents interest on borrowings under our credit facility as well as amortization of debt issuance costs. Interest expense increased by $1.7 million to $4.6 million for the three months ended June 30, 2013 compared to $2.9 million for the three months ended June 30, 2012. The increase in interest expense is primarily due to the expensing of $2.0 million in debt issuance costs related to our prior credit facility. Other factors contributing to the change are an increase in our weighted average debt outstanding during the respective periods and an increase in the amount of interest capitalized. Our weighted average debt outstanding for the three months ended June 30, 2013 was $249.7 million while the weighted average debt outstanding for the three months ended June 30, 2012 was $213.5 million, resulting in increased interest expense of $0.4 million. This increase was offset by an increase in the amount of interest capitalized of $0.4 million, from less than $0.1 million in the three months ended June 30, 2012 to $0.5 million for the three months ended June 30, 2013. During the three months ended June 30, 2012 and 2013, the weighted average interest rate under the credit agreement, excluding the $2.0 million of debt issuance costs related to the prior credit facility that was expensed, was 5.17% and 5.05%, respectively. As of June 30, 2013, borrowings under our amended and restated credit agreement bore interest at a weighted average interest rate of 3.29%.

Six Months Ended June 30, 2013 Compared to the Six Months Ended June 30, 2012

Service revenues. Service revenues include revenues from crude oil terminalling and storage services, crude oil pipeline services, crude oil trucking and producer field services and asphalt services. Service revenues, including reimbursement revenues of $3.7 million and $2.8 million for the six months ended June 30, 2013 and 2012, respectively, for fuel and power, property taxes, and insurance expenses related to the operations of our liquid asphalt facilities, were $91.9 million for the six months ended June 30, 2013 compared to $88.3 million for the six months ended June 30, 2012, an increase of $3.6 million, or 4%.

Crude oil terminalling and storage revenue decreased by $2.6 million to $16.0 million for the six months ended June 30, 2013 compared to $18.6 million for the six months ended June 30, 2012. This is primarily due to lower renegotiated storage rates with Vitol.

Crude oil pipeline services revenue decreased by $0.7 million to $9.9 million for the six months ended June 30, 2013 compared to $10.6 million for the six months ended June 30, 2012, primarily due to decreased throughput volumes on our Eagle North pipeline system. The decreased throughput on our Eagle North pipeline system is a result of a refinery turnaround, and we anticipate throughput to return to historical averages for the remainder of 2013.

Crude oil trucking and producer field services revenue increased by $3.9 million to $34.9 million for the six months ended June 30, 2013, compared to $31.0 million for the six months ended June 30, 2012. This increase is primarily the result of higher volumes of crude oil transported by our trucking assets.

Our asphalt services revenue, including reimbursement of fuel and power, property tax and insurance premiums, increased by $3.0 million to $31.1 million for the six months ended June 30, 2013, compared to $28.1 million for the six months ended June 30, 2012. The increase in revenue is primarily the result of increased product throughput at our facilities, short-term storage service agreements at certain of our facilities, and contractual rate escalations. In addition, reimbursement revenues increased by $0.9 million primarily as a result of increased fuel and power costs related to the operation of our facilities.

Operating expenses. Operating expenses were $63.9 million for the six months ended June 30, 2013 compared to $59.8 million for the six months ended June 30, 2012, an increase of $4.1 million, or 7%.

Crude oil terminalling and storage operating expenses decreased by $0.3 million to $3.5 million for the six months ended June 30, 2013 as compared to the six months ended June 30, 2012. This decrease is primarily the result of a decrease in depreciation expense. We do not currently anticipate significant variances in operating expenses related to our crude oil terminalling and storage assets for the remainder of 2013.

Our crude oil pipeline services operating expenses were $10.4 million for the six months ended June 30, 2013 compared to $11.4 million for the six months ended June 30, 2012. This decrease is primarily attributed to the idling of gathering lines associated with our Mid-Continent pipeline system in 2012 and the related $1.0 million impairment loss recorded in the six months ended June 30, 2012.

Our crude oil trucking and producer field services operating expenses increased by $4.1 million to $31.2 million for the six months ended June 30, 2013 compared to $27.1 million for the six months ended June 30, 2012. This increase was primarily driven by higher volumes of crude oil transported by our trucking assets, which resulted in higher driver commissions and fuel and fleet maintenance costs.

Our asphalt operating expenses were $18.8 million for the six months ended June 30, 2013 compared to $17.5 million for the six months ended June 30, 2012, an increase of $1.3 million. This is primarily due to increases in fuel and power costs incurred in connection with the operation of our asphalt facilities.

General and administrative expenses. General and administrative expenses decreased by $0.3 million, or 3%, to $9.2 million for the six months ended June 30, 2013 compared to $9.5 million for the six months ended June 30, 2012. The decrease was impacted by severance costs incurred in the first quarter of 2012 due to the resignation of a former executive officer and professional expenses related to the hiring of our Chief Executive Officer.

Gain on sale of assets. In the six months ended June 30, 2012, we recognized gains on the sale of assets of $5.2 million. The gains are primarily a result of the sale of 60,000 barrels of excess crude oil linefill attributed to our Longview pipeline system in East Texas. The linefill was sold to Vitol at the then-current market price for East Texas crude of $98.96 per barrel. This transaction resulted in a gain of approximately $4.5 million. The remaining gains resulted from the sale of surplus, used property and equipment. The $1.0 million of gains recorded in the six months ended June 30, 2013 included $0.9 million received from the Texas Department of Transportation to relocate segments of certain of our pipelines.

Interest expense. Interest expense represents interest on borrowings under our credit facility as well as amortization of debt issuance costs. Interest expense increased by $1.3 million to $7.3 million for the six months ended June 30, 2013 compared to $6.0 million for the six months ended June 30, 2012, primarily due to the expensing of $2.0 million in debt issuance costs related to our prior credit facility. Other factors contributing to the change are an increase in our weighted average debt outstanding during the respective periods and an increase in the amount of interest capitalized. Our weighted average debt outstanding for the six months ended June 30, 2013 was $237.2 million while the weighted average debt outstanding for the six months ended June 30, 2012 was $216.1 million, resulting in increased interest expense of $0.5 million. This increase was offset by an increase in the amount of interest capitalized of $0.6 million, from $0.1 million in the six months ended June 30, 2012 to $0.7 million for the six months ended June 30, 2013. During the six months ended June 30, 2012 and 2013, the weighted average interest rate under the credit agreement, excluding the $2.0 million of debt issuance costs related to the prior credit facility that was expensed, was 5.29% and 5.09%, respectively. As of June 30, 2013, borrowings under our amended and restated credit agreement bore interest at a weighted average interest rate of 3.29% .

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, 2012 and 2013:

	Six Months ended June 30,			
	2012		2013	
	(in millions)			
Net cash provided by operating activities	$28.7		$21.7	
Net cash used in investing activities	(5.9	)	(47.8	)
Net cash provided by (used in) financing activities	(20.2	)	27.7	

Operating Activities. Net cash provided by operating activities was $21.7 million for the six months ended June 30, 2013, as compared to $28.7 million for the six months ended June 30, 2012. The decrease in cash provided by operating activities is primarily the result of changes in working capital, which contributed approximately $6.7 million of the decrease.

Investing Activities. Net cash used in investing activities was $47.8 million for the six months ended June 30, 2013, as compared to $5.9 million of net cash provided by investing activities for the six months ended June 30, 2012. The increase in cash used in investing activities was primarily the result of an $18.8 million increase in capital expenditures, our $17.0 million investment in Advantage Pipeline and a decrease of $6.1 million in proceeds from the sale of assets in the six months ended June 30, 2013. Capital expenditures for the six months ended June 30, 2013 included maintenance capital expenditures of $7.2 million and expansion capital expenditures of $24.8 million.

Financing Activities. Net cash provided by financing activities was $27.7 million for the six months ended June 30, 2013, as compared to $20.2 million of net cash used in financing activities for the six months ended June 30, 2012. Financing activities for the six months ended June 30, 2013 consisted primarily of $16.5 million in distributions to our unitholders and net borrowings on long term debt of $51.4 million.

Our Liquidity and Capital Resources

Cash flow from operations and our credit facility are our primary sources of liquidity, although our ability to borrow such funds may be limited by the financial covenants in the credit facility. At June 30, 2013, we had a working capital deficit of $1.6 million. This is primarily a function of our approach to cash management. At June 30, 2013, we had approximately $137.1 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 August 2, 2013, we have aggregate unused commitments under our revolving credit facility of approximately $141.1 million, although our ability to borrow such funds may be limited by the financial covenants in our credit facility, and cash on hand of approximately $2.6 million.

Capital Requirements. Our capital requirements consist of the following:

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

Expansion capital expenditures for organic growth projects totaled $24.8 million in the six months ended June 30, 2013 compared to $7.3 million in the six months ended June 30, 2012. We currently expect our expansion capital expenditures for organic growth projects to be approximately $40.0 million to $50.0 million for all of 2013. Maintenance capital expenditures totaled $7.2 million in the six months ended June 30, 2013 compared to $5.9 million in the six months ended June 30, 2012. We currently expect maintenance capital expenditures to be approximately $14.0 million to $16.0 million in 2013.

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.

Description of Credit Facility. On June 28, 2013, we entered into an amended and restated credit agreement which consists of a $400.0 million revolving loan facility. Approximately $262.4 million was drawn on the closing date. The proceeds of loans made under our credit agreement may be used for working capital and other general corporate purposes. All references herein to the credit agreement on or after June 28, 2013 refer to the amended and restated credit agreement.

Our credit agreement is guaranteed by all of our existing subsidiaries. Obligations under our credit agreement are secured by first priority liens on substantially all of our assets and those of the guarantors, including all material pipeline, gathering and processing assets, all material storage tanks and asphalt facilities, all material working capital assets and a pledge of all of our equity interests in our subsidiaries.

Our credit agreement includes procedures for adding financial institutions as revolving lenders or for increasing the revolving commitment of any currently committed revolving lender subject to an aggregate maximum of $500.0 million for all revolving loan commitments under our credit agreement.

The credit agreement will mature on June 28, 2018, and all amounts outstanding under our credit agreement shall become due and payable on such date. We may prepay all loans under our 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 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 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 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%) plus an applicable margin that ranges from 1.0% to 2.0%.

We pay a per annum fee on all letters of credit issued under the credit agreement, which fee equals the applicable margin for loans accruing interest based on the eurodollar rate, and we pay a commitment fee on the unused commitments under the credit agreement. The credit agreement does not have a floor for the alternate base rate or the eurodollar rate. The applicable margins for the interest rate, the letter of credit fee and the commitment fee vary quarterly based on our consolidated total leverage ratio (as defined in the credit agreement, being generally computed as the ratio of consolidated total debt to consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges).

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

The maximum permitted consolidated total leverage ratio is 4.50 to 1.00, provided that the maximum consolidated total leverage ratio is 5.00 to 1.00 from and after (i) the last day of the fiscal quarter immediately preceding the fiscal quarter in which a specified acquisition (as defined in the credit agreement) occurs to and including the last day of the second full fiscal quarter following the fiscal quarter in which such specified acquisition occurred and (ii) the date on which we issue qualified senior notes (as defined in the credit agreement, but generally being unsecured indebtedness with no required principal payments prior to June 28, 2019) in an aggregate principal amount (when combined with all other qualified senior notes previously or concurrently issued) that equals or exceeds $200.0 million.
The maximum permitted consolidated senior secured leverage ratio (as defined in the credit agreement, but generally computed as the ratio of consolidated total secured debt to consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges) is 3.50 to 1.00, but this covenant is only tested from and after the date on which we issue qualified senior notes in an aggregate principal amount (when combined with all other qualified senior 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 our ability to:

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

At June 30, 2013, our consolidated total leverage ratio was 4.00 to 1.00 and the consolidated interest coverage ratio was 6.30 to 1.00. We were in compliance with all covenants of our credit agreement as of June 30, 2013.

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

Each of the following is an event of default under the credit agreement:
- failure to pay any principal, interest, fees, expenses or other amounts when due;
- failure to meet the quarterly financial covenants;

- failure to observe any other agreement, obligation or covenant in the credit agreement or any related loan document, subject to cure periods for certain failures;
- the failure of any representation or warranty to be materially true and correct when made;
- we, or any of our restricted subsidiaries, default under other indebtedness that exceeds a threshold amount;
- judgments against us or any of our restricted subsidiaries, in excess of a threshold amount;
- certain ERISA events involving us or our restricted subsidiaries resulting in a material adverse effect on us;
- bankruptcy or other insolvency events involving us or any of our restricted subsidiaries; and
- a change of control (as defined in the credit agreement, but generally being (i) the General Partner ceasing to own 100% of the our general partner interest or ceasing to control us, or (ii) Vitol and Charlesbank ceasing 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, all indebtedness under our credit agreement will immediately become due and payable. If any other event of default exists under our credit agreement, the lenders may accelerate the maturity of the obligations outstanding under our credit agreement and exercise other rights and remedies. In addition, if any event of default exists under our credit agreement, the lenders may commence foreclosure or other actions against the collateral.

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

Contractual Obligations. A summary of our contractual cash obligations over the next several fiscal years, as of June 30, 2013, 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]	$301.8	$7.9	$15.8	$278.1	$—
Operating lease obligations	19.2	6.1	9.3	2.8	1.0
Non-compete agreement[2]	0.2	0.1	0.1	—	—
Employee contract obligations[3]	0.2	0.1	0.1	—	—

(1) Represents required future principal repayments of borrowings of $262.4 million and variable rate interest payments of $39.4 million. At June 30, 2013, our borrowings had an interest rate of approximately 3.29%. 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 under a non-compete agreement related to our acquisition of certain field services assets.

(3) 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 15 to our 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 August 2, 2013 we had $258.9 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.

During the six months ended June 30, 2013, the weighted average interest rate under our credit agreement, excluding the $2.0 million of debt issuance costs related to the prior credit facility that was expensed, was 5.09%. As of June 30, 2013, borrowings under our credit facility bore interest at a weighted average interest rate of 3.29%.

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, 2013 and the terms of our credit agreement, an increase or decrease of 100 basis points in the interest rate would result in increased or decreased annual interest expense of approximately $2.6 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, 2013, 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, 2013 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 13 to our financial statements, and is incorporated herein by reference thereto.

Item 1A. Risk Factors

Information about risk factors for the three months ended June 30, 2013 does not differ materially from that set forth in Part I, Item 1A, of our Annual Report on Form 10-K for the year ended December 31, 2012.

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 7, 2013	By:	/s/ Alex G. Stallings Alex G. Stallings Chief Financial Officer and Secretary
Date:	August 7, 2013	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).
10.1	Amended and Restated Credit Agreement, dated as of June 28, 2013, among the Partnership, Wells Fargo Bank, National Association, as Administrative Agent, Lloyds TSB Bank PLC and Royal Bank of Canada, as Co-Syndication Agents, Natixis and SunTrust Bank, as Co-Documentation Agents, and the several lenders from time to time party thereto (filed as Exhibit 10.1 to the Partnership's Current Report on Form 8-K, filed July 1, 2013, 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 Annual Report on Form 10-Q for the quarter ended June 30, 2013, formatted in XBRL (eXtensible Business Reporting Language): (i) Document and Entity Information; (ii) Consolidated Balance Sheets as of December 31, 2012 and June 30, 2013; (iii) Consolidated Statements of Operations for the three and six months ended June 30, 2012 and 2013; (iv)Consolidated Statement of Changes in Partners' Capital for the six months ended June 30, 2013; (v) Consolidated Statements of Cash Flows for the six months ended June 30, 2012 and 2013; and (vi) Notes to Consolidated Financial Statements.

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* Filed herewith.

Furnished herewith

Application has been made to the Securities and Exchange Commission for confidential treatment of certain provisions of this exhibit. Omitted material for which confidential treatment has been requested has been separately filed with the Securities and Exchange Commission.