Blueknight Energy Partners, L.P.
Form 10-Q
May 08, 2013

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

FORM 10-Q

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

For the quarterly period ended March 31, 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 ý No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No o

Indicate by check mark 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 ý
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 ý

As of May 3, 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 March 31, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	$3,177	$176
Accounts receivable, net of allowance for doubtful accounts of $469 and $500 at December 31, 2012 and March 31, 2013, respectively	9,948	11,997
Receivables from related parties, net of allowance for doubtful accounts of $0 for both dates	3,522	2,351
Prepaid insurance	1,237	645
Assets held for sale	281	45
Other current assets	1,822	1,794
Total current assets	19,987	17,008
Property, plant and equipment, net of accumulated depreciation of $153,216 and $158,888 at December 31, 2012 and March 31, 2013, respectively	267,741	275,985
Investment in unconsolidated affiliate	—	13,944
Goodwill	7,216	7,216
Debt issuance costs, net	3,225	2,993
Intangibles and other assets, net	1,656	1,567
Total assets	$299,825	$318,713
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$10,052	$8,512
Accrued interest payable	164	295
Accrued interest payable to related parties	304	235
Accrued property taxes payable	1,938	1,468
Unearned revenue	4,068	4,518
Unearned revenue with related parties	316	245
Accrued payroll	6,409	3,590
Other current liabilities	4,032	3,474
Current portion of long-term payable to related parties	1,881	1,625
Total current liabilities	29,164	23,962
Long-term payable to related parties	800	610
Other long-term liabilities	206	123
Long-term debt (including $15.0 million with related parties for both dates)	211,000	237,000
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 units issued and outstanding for both dates)	464,433	462,794

General partner interest (2.1% with 1,127,755 general partner units outstanding for both dates)	(610,377)	(610,375)
Total Partners' capital	58,655	57,018
Total liabilities and Partners' capital	$299,825	$318,713

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

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

	Three Months ended March 31,	
	2012	2013
	(unaudited)	
Service revenue:		
Third party revenue	$33,134	$33,105
Related party revenue	11,443	12,479
Total revenue	44,577	45,584
Expenses:		
Operating	29,288	31,811
General and administrative	5,103	4,667
Total expenses	34,391	36,478
Gain (loss) on sale of assets	4,955	(222)
Operating income	15,141	8,884
Other income (expense):		
Equity earnings (loss) in unconsolidated affiliate	—	(56)
Interest expense (net of capitalized interest of $28 and $242, respectively)	(3,071)	(2,732)
Income before income taxes	12,070	6,096
Provision for income taxes	76	74
Net income	$11,994	$6,022
Allocation of net income for calculation of earnings per unit:		
General partner interest in net income	$308	$187
Preferred interest in net income	$5,391	$5,391
Beneficial conversion feature attributable to Preferred Units	$1,853	$—
Income available to limited partners	$4,442	$444
Basic and diluted net income per common unit	$0.20	$0.02
Weighted average common units outstanding - basic and diluted	22,660	22,675

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	505	5,391	126	6,022
Equity-based incentive compensation	515	—	11	526
Profits interest contribution	—	—	37	37
Distributions	(2,659)	(5,391)	(172)	(8,222)
Balance, March 31, 2013	$462,794	$204,599	$(610,375)	$57,018

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

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

	Three Months ended March 31, 2012	2013
	(unaudited)	
Cash flows from operating activities:		
Net income	$11,994	$6,022
Adjustments to reconcile net income to net cash provided by operating activities:		
Provision for uncollectible receivables from third parties	—	31
Depreciation and amortization	5,655	5,823
Amortization and write-off of debt issuance costs	444	455
(Gain) loss on sale of assets	(4,955)	222
Equity-based incentive compensation	275	526
Equity (earnings) loss in unconsolidated affiliate	—	56
Changes in assets and liabilities		
Decrease (increase) in accounts receivable	3,139	(2,080)
Decrease in receivables from related parties	1,754	1,171
Decrease in prepaid insurance	858	659
Decrease (increase) in other current assets	(1,196)	28
Decrease in other assets	29	15
Decrease in accounts payable	(1,868)	(1,680)
Increase (decrease) in accrued interest payable	(5)	131
Decrease in accrued interest payable to related parties	(201)	(69)
Decrease in accrued property taxes	(564)	(470)
Increase in unearned revenue	2,896	450
Increase (decrease) in unearned revenue from related parties	976	(71)
Increase in accrued payroll	(2,306)	(2,819)
Increase (decrease) in other accrued liabilities	446	(401)
Net cash provided by operating activities	17,371	7,999
Cash flows from investing activities:		
Capital expenditures	(6,207)	(13,907)
Proceeds from sale of assets	6,818	1
Investment in unconsolidated affiliate	—	(14,000)
Net cash provided by (used in) investing activities	611	(27,906)
Cash flows from financing activities:		
Payment on insurance premium financing agreement	(142)	(240)
Debt issuance costs	—	(223)
Payments on long-term payable to related party	(388)	(446)
Borrowings under credit facility	12,000	30,000
Payments under credit facility	(18,000)	(4,000)
Capital contribution related to profits interest (see Note 10)	—	37
Distributions	(7,756)	(8,222)
Net cash provided by (used in) financing activities	(14,286)	16,906
Net increase (decrease) in cash and cash equivalents	3,696	(3,001)
Cash and cash equivalents at beginning of period	1,239	3,177
Cash and cash equivalents at end of period	$4,935	$176

Supplemental disclosure of cash flow information:

Increase (decrease) in accounts payable related to purchase of property, plant and equipment	$(769)	$140

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, the consolidated statement of changes in partners' capital and the statement of cash flows for the three months ended March 31, 2012 and 2013, and the consolidated balance sheet as of March 31, 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 “Equity earnings in unconsolidated affiliate, net of distributions.” 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).

4. PROPERTY, PLANT AND EQUIPMENT

	Estimated Useful Lives (Years)	December 31, 2012	March 31, 2013
		(dollars in thousands)	
Land	N/A	$16,405	$16,435
Land improvements	10-20	6,287	6,313
Pipelines and facilities	5-30	101,392	104,173
Storage and terminal facilities	10-35	232,102	233,019
Transportation equipment	3-10	18,003	18,355
Office property and equipment and other	3-20	26,009	26,602
Pipeline linefill and tank bottoms	N/A	5,993	5,993
Construction-in-progress	N/A	14,766	23,983
Property, plant and equipment, gross		420,957	434,873
Accumulated depreciation		(153,216)	(158,888)
Property, plant and equipment, net		$267,741	$275,985

Depreciation expense for the three months ended March 31, 2012 and 2013 was $5.6 million and $5.8 million, respectively.

5. DEBT

On October 25, 2010, the Partnership entered into a new credit agreement, which includes a $200.0 million term loan facility and a $75.0 million revolving loan facility. On April 5, 2011, the Partnership entered into a Joinder Agreement whereby the Partnership's revolving credit facility was increased from $75.0 million to $95.0 million. As of May 3, 2013, approximately $200.0 million of term loan borrowings, $42.0 million of revolver borrowings and $0.5 million of letters of credit were outstanding under the credit facility, leaving the Partnership with approximately $52.5 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. Vitol Inc. (together with its affiliates, "Vitol") is a lender under the credit agreement and has committed to loan the Partnership $15.0 million pursuant to such agreement. The proceeds of loans made under the credit agreement may be used for working capital and other general corporate purposes of the Partnership.

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 $200.0 million for all revolving loan commitments under the credit agreement.

The credit agreement will mature on October 25, 2014, 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, casualty events and debt incurrences and, in certain circumstances, with a portion of the Partnership's excess cash flow (as defined in the credit agreement). These mandatory prepayments will be applied to the term loan under the credit agreement until it is repaid in full, then applied to reduce commitments under the revolving loan facility.

Borrowings under the credit agreement bear interest, at the Partnership's option, at either (i) the ABR (the highest of the administrative agent's prime rate, the federal funds rate plus 0.5%, or the one-month eurodollar rate (as defined in the credit agreement) plus 1.0%), plus an applicable margin that ranges from 3.0% to 3.5%, or (ii) the eurodollar rate plus an applicable margin that ranges from 4.0% to 4.5%, in each case depending on the Partnership's consolidated total leverage ratio (as defined in the credit agreement). 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 of 0.5% per annum on the unused availability under the credit agreement. The credit agreement does not have a floor for the ABR or the eurodollar rate. In connection with entering into the 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. Vitol received its pro rata portion of such fees as a lender under the credit agreement.

In March 2013 the Partnership amended its credit facility to, among other things:

- eliminate the requirement that its consolidated total leverage ratio not exceed 4.00 to 1.00 for purposes of making distributions;
- increase the Partnership’s ability to make investments in joint ventures and subsidiaries without such joint ventures and subsidiaries becoming guarantors under the credit facility; and
- permit the Partnership to include projected EBITDA from material projects (generally being the construction or expansion of any capital project the aggregate budgeted capital cost of which exceeds $5.0 million) in its EBITDA for purposes of calculating compliance with the credit facility’s minimum consolidated interest coverage ratio and maximum consolidated total leverage ratio. The amount of projected EBITDA from material projects that is included in such financial covenant calculations is subject to the credit facility administrative agent’s approval, and the aggregate amount of all material project EBITDA adjustments during any period is limited to 15% of the total actual consolidated EBITDA for such period.

In connection with entering into the March 2013 credit facility amendment, the Partnership paid a fee to the consenting lenders.

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 for the fiscal quarter ended March 31, 2013 and each fiscal quarter ending thereafter. The minimum permitted consolidated interest coverage ratio (as defined in the credit agreement) is 3.00 to 1.00 for the fiscal quarter ended March 31, 2013 and each fiscal quarter ending thereafter.

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 activities;
- 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 March 31, 2013, the Partnership's leverage ratio was 3.43 to 1.00 and the interest coverage ratio was 6.78 to 1.00. The Partnership was in compliance with all covenants of its credit agreement as of March 31, 2013.

As of March 31, 2013, the credit agreement permitted the Partnership to make quarterly distributions of available cash (as defined in the Partnership's partnership agreement) to unitholders so long as: (i) no default or event of default exists under the credit agreement, (ii) the Partnership has, on a pro forma basis after giving effect to such distribution, at least $10.0 million of availability under the revolving loan facility, and (iii) the Partnership's consolidated total leverage ratio, on a pro forma basis, would not be greater than 4.50 to 1.00. In March 2013, the credit agreement was amended to, among other things, eliminate the requirement that the Partnership's consolidated total leverage ratio not exceed 4.00 to 1.00 for purposes of making distributions. The Partnership is currently allowed to make distributions to its unitholders in accordance with these covenants; however, the Partnership will only make distributions to the extent it has sufficient cash from operations after establishment of cash reserves as determined by the 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 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 subsidiaries', default under other indebtedness that exceeds a threshold amount;
- judgments against the Partnership or any of its subsidiaries in excess of a threshold amount;
- certain material ERISA events involving the Partnership or any of its subsidiaries;
- bankruptcy or other insolvency events involving the Partnership or any of its subsidiaries; and
- a change of control (as defined in the credit agreement).

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.

It will constitute a change of control under the credit agreement if either Vitol or Charlesbank ceases to own, directly or indirectly, exactly 50% of the membership interests of Blueknight Energy Partners G.P., L.L.C. (the "General Partner") (other than a non-voting economic interest owned by the Partnership's chief executive officer, Mr. Mark Hurley, in Blueknight GP Holding, LLC ("HoldCo"), the owner of the General Partner) or if the General Partner ceases to be controlled by both Vitol and Charlesbank.

Interest expense related to debt issuance cost amortization for the three months ended March 31, 2012 and 2013 was $0.4 million and $0.5 million, respectively. The Partnership capitalized debt issuance costs of $0.2 million in the three months ended March 31, 2013. The Partnership did not incur any debt issuance costs in the three months ended March 31, 2012.

During the three months ended March 31, 2012 and 2013, the weighted average interest rate under the credit agreement incurred by the Partnership was 4.69% and 4.43%, respectively, and the total weighted average interest rate, including interest associated with the ENPS Throughput Agreement (as defined in Note 8), was 5.67% and 5.34%, respectively, resulting in interest expense of approximately $3.1 million and $2.7 million, respectively. During the three months ended March 31, 2012 and 2013, the Partnership capitalized interest of less than $0.1 million and $0.2 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 March 31,	
	2012	2013
Net income	$11,994	$6,022
General partner interest in net income	308	187
Preferred interest in net income	5,391	5,391
Beneficial conversion feature attributable to preferred units	1,853	—
Income available to limited partners	$4,442	$444
Basic and diluted weighted average number of units:		
Common units	22,660	22,675
Restricted and phantom units	398	564
Basic and diluted net income per common unit	$0.20	$0.02

7. DISTRIBUTIONS

On April 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 March 31, 2013. The Partnership will pay this distribution on the preferred units on May 15, 2013 to unitholders of record as of May 3, 2013.

In addition, the Board declared a cash distribution of $0.1175 per unit on its outstanding common units, a 2.2% increase over the previous quarter's distribution. The distribution will be paid on May 15, 2013 to unitholders of record on May 3, 2013. The distribution is for the three months ended March 31, 2013. The total distribution will be approximately $2.8 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 March 31, 2012 and 2013, the Partnership recognized revenues of $11.4 million and $12.5 million, respectively, for services provided to Vitol. As of December 31, 2012 and March 31, 2013, the Partnership had receivables from Vitol of $3.1 million and $1.9 million, respectively. The Partnership also had a receivable from its General Partner of $0.5 million for both December 31, 2012 and March 31, 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 three months ended March 31, 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 $3.3 million from Vitol with respect to services provided pursuant to the 2008 Vitol Storage Agreement for the three months ended March 31, 2012. 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 $3.1 million and $2.6 million during the three months ended March 31, 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 Vitol 12-month Storage Agreement is 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 $1.2 million for the three months ended March 31, 2013.

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 $0.6 million for the three months ended March 31, 2013.

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 $0.6 million for the three months ended March 31, 2013.

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 will pay additional usage fees for every barrel delivered by or on behalf of Vitol on ENPS. This $5.5 million fee received from Vitol is accounted for as a long-term payable to a related party and is reflected as such on the Partnership’s consolidated balance sheet as of March 31, 2013. 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 each of the three months ended March 31, 2012 and 2013, the Partnership incurred interest expense under this agreement of approximately $0.1 million. 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 shall continue for five years. During the three months ended March 31, 2013, the Partnership generated revenues of $0.2 million under this agreement. The Partnership believes that the rates it charges Vitol under this 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 this 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 term of the Vitol Shared Services Agreement commenced on August 1, 2012 and shall continue for one year. The Vitol Shared Services Agreement renews annually unless terminated by either party as provided in the agreement. During the three months ended March 31, 2013, the Partnership generated revenues of less than $0.1 million under this agreement. The Partnership believes that the rates it charges Vitol under this agreement are fair and reasonable to the Partnership and its unitholders. The Board’s conflicts committee reviewed and approved this 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 is a lender under the Partnership’s current credit agreement and has committed to loan the Partnership $15.0 million pursuant to such agreement. During each of the three months ended March 31, 2012 and 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 in connection therewith.

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 months ended March 31, 2013, the Partnership did not generate any revenues 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. On September 14, 2011, the Partnership’s unitholders approved an amendment to the LTIP to increase the number of common units issuable under such plan by 1.35 million common units from 1.25 million common units to 2.6 million common units. 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 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 common 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, and the unrecognized estimated compensation cost at March 31, 2013 was $2.6 million, which will be recognized over the remaining vesting period. As of March 31, 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 March 31, 2013 was $2.5 million and will be expensed over the remaining vesting period.

The Partnership's equity-based incentive compensation expense for the three months ended March 31, 2012 and 2013 was $0.3 million and $0.5 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	251,106	8.75
Vested	3,734	7.37
Forfeited	16,600	7.24
Nonvested at March 31, 2013	1,247,475	$6.95

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 for each of the three months ended March 31, 2012 and 2013 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 March 31, 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, and 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 March 31, 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 March 31, 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 March 31, 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 March 31, 2012					
Service revenue					
Third party revenue	$2,645	$4,465	$12,778	$13,246	$33,134
Related party revenue	6,601	1,331	3,219	292	11,443
Total revenue for reportable segments	9,246	5,796	15,997	13,538	44,577
Operating expenses (excluding depreciation and amortization)	710	3,949	13,101	5,873	23,633
Operating margin (excluding depreciation and amortization)(1)	8,536	1,847	2,896	7,665	20,944
Total assets (end of period)	70,813	97,614	17,383	115,533	301,343
Three months ended March 31, 2013					
Service revenue					
Third party revenue	$2,867	$4,162	$12,017	$14,059	$33,105
Related party revenue	5,438	1,233	5,310	498	12,479
Total revenue for reportable segments	8,305	5,395	17,327	14,557	45,584
Operating expenses (excluding depreciation and amortization)	816	3,940	15,219	6,013	25,988
Operating margin (excluding depreciation and amortization)(1)	7,489	1,455	2,108	8,544	19,596
Total assets (end of period)	63,816	128,733	21,328	104,836	318,713

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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 March 31,	
	2012	2013
Operating margin (excluding depreciation and amortization)	$20,944	$19,596
Depreciation and amortization	(5,655)	(5,823)
General and administrative expenses	(5,103)	(4,667)
Gain (loss) on sale of assets	4,955	(222)
Interest expense	(3,071)	(2,732)
Equity earnings (loss) in unconsolidated entity	$—	$(56)
Income before income taxes	$12,070	$6,096

13. COMMITMENTS AND CONTINGENCIES

The Partnership is from time to time subject to various legal actions and claims incidental to its business, including those arising out of environmental-related matters. 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 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 Department of Labor.

On July 8, 2009, the nine executives 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 the Partnership filed. 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 has 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. Cross-motions have been filed in the appellate court seeking attorney's fees and costs incurred during the pendency of the appeal. The Oklahoma Court of Civil Appeals has not issued rulings on these motions. While the Partnership believes it has meritorious defenses against the damages and attorneys' fees sought to be recovered, the ultimate resolution of the matter cannot be determined.

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. On April 16, 2013, Koch filed an answer to the complaint and a counterclaim, and the Partnership is in the process of preparing a response to the counterclaim. 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 has filed a motion for summary judgment against these claims, and a trial date is set for May 31, 2013. The Partnership intends to vigorously defend these claims.

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 has been referred to a special master for report and recommendation. Discovery, before the special master, is ongoing and 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 certain unknown 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 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 March 31, 2013 are presented below (dollars in thousands):

Deferred tax assets	
Difference in bases of property, plant and equipment	$1,057
Deferred tax asset	1,057
Less: valuation allowance	(1,057)
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, 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) "SemCorp" refers to SemGroup Corporation and its predecessors (including SemGroup, L.P.), subsidiaries and affiliates (other than our General Partner and us during periods in which we were affiliated with SemGroup, L.P.), (4) Vitol refers to Vitol Holding B.V., its affiliates and subsidiaries (other than our General Partner and us) and (5) 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 March 4, 2013, we amended our credit facility to, among other things, (i) eliminate the requirement that our consolidated total leverage ratio not exceed 4.00 to 1.00 for purposes of making distributions, (ii) increase our ability to make investments in joint ventures and subsidiaries without such joint ventures and subsidiaries becoming guarantors under our credit facility, and (iii) permit us to include projected EBITDA from material projects for purposes of calculating compliance with our credit facility’s minimum consolidated interest coverage ratio and maximum consolidated total leverage ratio.

Our Revenues

Our revenues consist of (i) terminalling and storage revenues, (ii) gathering, transportation and producer field services revenues and (iii) fuel surcharge revenues. For the three months ended March 31, 2013, we derived approximately 27% of our revenues from services we provided to Vitol, with the remainder of our services being provided to third parties.

Our revenues increased by $1.0 million, or 2%, for the three months ended March 31, 2013 as compared to the three months ended March 31, 2012. This increase is primarily attributed to higher rates for the majority of our crude oil trucking service contracts as well as increased utilization of 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 May 3, 2013, we had approximately 6.0 million barrels of crude oil storage under service contracts with remaining terms ranging from month-to-month to 24 months, including 4.2 million barrels under contract to Vitol. As of May 3, 2013, 1.7 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 with 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 March 31, 2013, we transported approximately 61,000 barrels per day on our pipelines, a decrease of 7% as compared to the three months ended March 31, 2012. Vitol accounted for 21% of volumes transported in the three months ended March 31, 2013.

For the three months ended March 31, 2013, we transported approximately 56,400 barrels per day on our crude transport trucks, an increase of 5% as compared to the three months ended March 31, 2012. Vitol accounted for approximately 43% of volumes transported in the three months ended March 31, 2013. While we see opportunity to increase the utilization of our crude oil trucking and producer field services assets due to high demand for our services in the markets we currently serve, demand outpaces supply for qualified drivers in this industry and is delaying our realization of complete utilization of these assets. We are actively pursuing additional drivers, and we anticipate increased utilization of these assets throughout 2013. However, there can be no assurance that our efforts will be successful.

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

Our Expenses

Operating expenses increased by $2.5 million, or 9%, for three months ended March 31, 2013 as compared to three months ended March 31, 2012. Approximately $1.0 million of this increase is due to increases in compensation costs, including commissions, insurance and the recognition of compensation expense associated with awards under our General Partner’s long-term incentive plan. The remainder is primarily attributed to an increase in maintenance and repairs. General and administrative expenses decreased by $0.4 million, or 8%, in the first quarter of 2013 as compared to 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.

Maintenance capital expenditures were $3.7 million and $3.4 million and expansion capital expenditures were $10.2 million and $2.8 million in the three months ended March 31, 2013 and 2012, respectively. Our interest expense decreased by $0.4 million during the three months ended March 31, 2013 as compared to the three months ended March 31, 2012, primarily as a result of a decrease in our weighted average interest rate and an increase in the amount of interest capitalized.

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 March 31, 2013.

Distributions

We did not make a distribution to our common unitholders or subordinated unitholders from May 15, 2008 through February 13, 2012 due, in part, to the events of default that existed under our former credit agreement, restrictions under such credit agreement and the uncertainty of our future cash flows relating to SemCorp's bankruptcy filings. Our unitholders will be required to pay taxes on their share of our taxable income even though they did not receive a distribution for the quarters ended June 30, 2008 through September 30, 2011. We resumed distributions for common units on February 14, 2012 for the quarter ended December 31, 2011, and we continued to make quarterly distributions throughout 2012. The amount of distributions paid 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 April 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 March 31, 2013. We will pay this distribution on the preferred units on May 15, 2013 to unitholders of record as of May 3, 2013.

In addition, we declared a cash distribution of $0.1175 per unit on our outstanding common units, a 2.2% increase over the previous quarter's distribution. The distribution will be paid on May 15, 2013 to unitholders of record on

May 3, 2013. The distribution is for the three months ended March 31, 2013. The total distribution to be paid is approximately $2.8 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 service agreement. The initial term of the first agreement is 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 service 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 months ended March 31, 2012 and 2013:

	Three Months ended March 31,	
	2012	2013
Service revenues:		
Crude oil terminalling and storage revenues:		
Third party	$2,645	$2,867
Related party	6,601	5,438
Total crude oil terminalling and storage	9,246	8,305
Crude oil pipeline services revenues:		
Third party	4,465	4,162
Related party	1,331	1,233
Total crude oil pipeline services revenues	5,796	5,395
Crude oil trucking and producer field services revenues:		
Third party	12,778	12,017
Related party	3,219	5,310
Total crude oil trucking and producer field services revenues	15,997	17,327
Asphalt services revenues:		
Third party	13,246	14,059
Related party	292	498
Total asphalt services	13,538	14,557
Total revenues	44,577	45,584
Operating expenses:		
Crude oil terminalling and storage	1,742	1,659
Crude oil pipeline services	5,203	5,363
Crude oil trucking and producer field services	13,445	15,679
Asphalt services	8,898	9,110
Total operating expenses	29,288	31,811
General and administrative expenses	5,103	4,667
Gain (loss) on sale of assets	4,955	(222)
Operating income	15,141	8,884
Other income (expense):		
Equity earnings (loss) in unconsolidated affiliate	—	(56)
Interest expense	(3,071)	(2,732)
Income tax expense	(76)	(74)
Net income	$11,994	$6,022

Three Months Ended March 31, 2013 Compared to the Three Months Ended March 31, 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 $1.6 million and $1.4 million for the three months ended March 31, 2013 and 2012, respectively, for fuel and power, property tax, and insurance expenses related to the operations of our liquid asphalt facilities, were $45.6 million for the

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three months ended March 31, 2013 compared to $44.6 million for the three months ended March 31, 2012, an increase of $1.0 million, or 2%.

Crude oil terminalling and storage revenue decreased by $0.9 million to $8.3 million for the three months ended March 31, 2013 compared to $9.2 million for the three months ended March 31, 2012. 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.

Crude oil pipeline services revenue decreased by $0.4 million to $5.4 million for the three months ended March 31, 2013 compared to $5.8 million for the three months ended March 31, 2012, primarily due to decreased throughput volumes on our Eagle North pipeline system. This resulted in our deferring revenue of $0.4 million during the three months ended March 31, 2013 under a contractual minimum throughput agreement associated with our Eagle North pipeline.

Crude oil trucking and producer field services revenue increased by $1.3 million to $17.3 million for the three months ended March 31, 2013, compared to $16.0 million for the three months ended March 31, 2012. This increase is primarily the result of higher rates for the majority of our crude oil trucking service contracts as well as increased utilization of our trucking assets.

Our asphalt services revenue, including reimbursement of fuel and power, property tax and insurance premiums, increased by $1.1 million to $14.6 million for the three months ended March 31, 2013, compared to $13.5 million for the three months ended March 31, 2012. The increase in revenue is primarily due to short-term storage service agreements at certain of our facilities. Escalations in rates due to CPI adjustments also contributed to the increase in revenues.

Operating expenses. Operating expenses were $31.8 million for the three months ended March 31, 2013 compared to $29.3 million for the three months ended March 31, 2012, an increase of $2.5 million, or 9%.

Crude oil terminalling and storage operating expenses remained consistent at $1.7 million for the three months ended March 31, 2013 and 2012. 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 $5.4 million for the three months ended March 31, 2013 compared to $5.2 million for the three months ended March 31, 2012. This decrease is primarily attributed to the idling of gathering lines associated with our Mid-Continent pipeline system in 2012.

Our crude oil trucking and producer field services operating expenses increased by $2.3 million to $15.7 million for the three months ended March 31, 2013 compared to $13.4 million for the three months ended March 31, 2012. This increase was primarily driven by the increase in utilization of our trucking assets, which resulted in higher driver commissions and fuel and fleet maintenance costs.

Our asphalt operating expenses were $9.1 million for the three months ended March 31, 2013 compared to $8.9 million for the three months ended March 31, 2012, an increase of $0.2 million.

General and administrative expenses. General and administrative expenses decreased by $0.4 million, or 8%, to $4.7 million for the three months ended March 31, 2013 compared to $5.1 million for the three months ended March 31, 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 three months ended March 31, 2012, we recognized gains on the sale of assets of $5.0 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 for the 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 loss recorded in three months ended March 31, 2013 resulted from the sale of surplus, used property and equipment.

Interest expense. Interest expense represents interest on borrowings under our credit facility as well as amortization of debt issuance costs. Interest expense decreased by $0.4 million to $2.7 million for the three months ended March 31, 2013 compared to $3.1 million for the three months ended March 31, 2012 due to a decrease in our weighted average interest rate and an increase in the amount of interest capitalized. During the three months ended March 31, 2012 and 2013, the weighted average interest rate under the credit agreement incurred by us was 4.69% and 4.43%, respectively, and the total weighted average interest rate, including interest associated with the ENPS Throughput Agreement, was 5.67% and 5.34%, respectively, resulting in interest expense of approximately $3.1 million and $2.7 million, respectively. During the three months ended March 31, 2012 and 2013, we capitalized interest of less than $0.1 million and $0.2 million, respectively.

Effects of Inflation

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

Off Balance Sheet Arrangements

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

Liquidity and Capital Resources

Cash Flows and Capital Expenditures

The following table summarizes our sources and uses of cash for the three months ended March 31, 2010, 2012 and 2013:

	Three Months ended March 31,	
	2012	2013
	(in millions)	
Net cash provided by operating activities	$17.4	$8.0
Net cash provided by (used in) investing activities	0.6	(27.9)
Net cash provided by (used in) financing activities	(14.3)	16.9

Operating Activities. Net cash provided by operating activities was $8.0 million for the three months ended March 31, 2013, as compared to $17.4 million for the three months ended March 31, 2012. The decrease in cash provided by operating activities is primarily the result of changes in working capital, which contributed to approximately $9.1 million of the decrease.

Investing Activities. Net cash used in investing activities was $27.9 million for the three months ended March 31, 2013, as compared to $0.6 million of net cash provided by investing activities for the three months ended March 31, 2012. The increase in cash used in investing activities was primarily the result of a $7.7 million increase in capital expenditures and a decrease of $6.8 million in proceeds from the sale of assets in the three months ended March 31, 2013. Capital expenditures for the three months ended March 31, 2013 included maintenance capital expenditures of $3.7 million and expansion capital expenditures of $10.2 million. In addition, we made a $14.0 million investment in Advantage Pipeline in the three months ended March 31, 2013.

Financing Activities. Net cash provided by financing activities was $16.9 million for the three months ended March 31, 2013, as compared to $14.3 million of net cash used in financing activities for the three months ended March 31, 2012. Financing activities for the three months ended March 31, 2013 consisted primarily of $8.2 million in distributions to our unitholders and net borrowings on long term debt of $26.0 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 March 31, 2013, we had a working capital deficit of $7.0 million. This is primarily a function of our approach to cash management. At March 31, 2013, we had approximately $57.5 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 May 3, 2013, we have aggregate unused commitments under our revolving credit facility of approximately $52.5 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 $1.4 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 $10.2 million in the three months ended March 31, 2013 compared to $2.8 million in the three months ended March 31, 2012. We currently expect expansion capital expenditures for organic growth projects to be approximately $40.0 million to $50.0 million in 2013. Maintenance capital expenditures totaled $3.7 million in the three months ended March 31, 2013 compared to $3.4 million in the three months ended March 31, 2012. We currently expect maintenance capital expenditures to be approximately $11.0 million to $14.0 million in 2013.

Our Ability to Grow Depends on Our Ability to Access External Expansion Capital. Our partnership agreement provides 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 October 25, 2010, we entered into a new credit agreement, which we refer to as our credit agreement. Our credit agreement includes a $200.0 million term loan facility and, after giving effect to an April 5, 2011 amendment, a $95.0 million revolving credit facility. Vitol is a lender under our credit agreement and has committed to loan us $15.0 million pursuant to such agreement. The proceeds of loans made under our credit agreement may be used for working capital and other general corporate purposes.

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 $200.0 million for all revolving loan commitments under our credit agreement.

The credit agreement will mature on October 25, 2014, 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 of certain asset sales, casualty events and debt incurrences, and, in certain circumstances, with a portion of our excess cash flow (as defined in the credit agreement). These mandatory prepayments will be applied to the term loan under our credit agreement until it is repaid in full, then applied to reduce commitments under the revolving loan facility.

Borrowings under our credit agreement bear interest, at our option, at either (i) the ABR (the highest of the administrative agent's prime rate, the federal funds rate plus 0.5%, or the one-month eurodollar rate (as defined in the credit agreement) plus 1%), plus an applicable margin that ranges from 3.0% to 3.5%, or (ii) the eurodollar rate plus an applicable margin that ranges from 4.0% to 4.5%, in each case depending on our consolidated total leverage ratio (as defined in the credit agreement).

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 of 0.5% per annum on the unused availability under the credit agreement. The credit agreement does not have a floor for the ABR or the eurodollar rate. In connection with entering into our credit agreement, we paid certain upfront fees to the lenders thereunder, and we paid certain arrangement and other fees to the arranger and administrative agent of our credit agreement. Vitol received its pro rata portion of such fees as a lender under our credit agreement. During the three months ended March 31, 2013, our weighted average interest rate was 5.34%, including interest under the throughput capacity agreement with Vitol related to our Eagle North pipeline system and the amortization of debt issuance costs, resulting in interest expense of approximately $2.7 million.

In March 2013 we amended our credit facility to, among other things:

- eliminate the requirement that our consolidated total leverage ratio not exceed 4.00 to 1.00 for purposes of making distributions;

- increase our ability to make investments in joint ventures and subsidiaries without such joint ventures and subsidiaries becoming guarantors under our credit facility; and
- permit us to include projected EBITDA from material projects (generally being the construction or expansion of any capital project the aggregate budgeted capital cost of which exceeds $5.0 million) in our EBITDA for purposes of calculating compliance with our credit facility's minimum consolidated interest coverage ratio and maximum consolidated total leverage ratio. The amount of projected EBITDA from material projects that is included in such financial covenant calculations is subject to the credit facility administrative agent's approval, and the aggregate amount of all material project EBITDA adjustments during any period is limited to 15% of the total actual consolidated EBITDA for such period.

In connection with entering into the March 2013 credit facility amendment, we paid a fee to the consenting lenders.

Our 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 for the fiscal quarter ended March 31, 2013 and each fiscal quarter ending thereafter. The minimum permitted consolidated interest coverage ratio (as defined in our credit agreement) is 3.00 to 1.00 for the fiscal quarter ended March 31, 2013 and each fiscal quarter ending thereafter.

In addition, our 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 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 our business;
- enter into operating leases; and
- make certain amendments to our partnership agreement.

At March 31, 2013, our leverage ratio was 3.43 to 1.00 and the interest coverage ratio was 6.78 to 1.00. We were in compliance with all covenants of our credit agreement as of March 31, 2013.

As of March 31, 2013, the credit agreement permitted us to make quarterly distributions of available cash (as defined in our partnership agreement) to unitholders so long as: (i) no default or event of default exists under our credit agreement, (ii) we have, on a pro forma basis after giving effect to such distribution, at least $10.0 million of availability under the revolving loan facility, and (iii) our consolidated total leverage ratio, on a pro forma basis, would not be greater than 4.50 to 1.00. In March 2013, the credit agreement was amended to, among other things, eliminate the requirement that our consolidated total leverage ratio not exceed 4.00 to 1.00 for purposes of making distributions. We are currently allowed to make distributions to our unitholders in accordance with these covenants; however, we will only make distributions to the extent we have sufficient cash from operations after establishment of cash reserves as determined by our 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 our 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;

- our, or any of our subsidiaries', default under other indebtedness that exceeds a threshold amount;
- judgments against us or any of our subsidiaries in excess of a threshold amount;
- certain material ERISA events involving us or any of our subsidiaries;
- bankruptcy or other insolvency events involving us or any of our subsidiaries; and
- a change of control (as defined in the credit agreement).

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.

It will constitute a change of control under our credit agreement if either Vitol or Charlesbank ceases to own, directly or indirectly, exactly 50% of the membership interests of our General Partner (other than a non-voting economic interest owned by Mr. Hurley in Blueknight GP Holding, LLC, the owner of our General Partner) or if our General Partner ceases to be controlled by both Vitol and Charlesbank.

Contractual Obligations. A summary of our contractual cash obligations over the next several fiscal years, as of March 31, 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]	$253.2	$10.3	$242.9	$—	$—
Operating lease obligations	20.0	6.0	9.7	3.0	1.3
Related party throughput capacity agreement[2]	2.4	1.8	0.6	—	—
Non-compete agreement[3]	0.2	0.1	0.1	—	—
Employee contract obligations[4]	0.3	0.1	0.2	—	—

(1) Represents required future principal repayments of borrowings of $237.0 million and variable rate interest payments of $16.2 million. At March 31, 2013, our borrowings had an interest rate of approximately 4.21%. This interest rate was used to calculate future interest payments. All amounts outstanding under our credit agreement mature in October 2014.

(2) Represents required future repayments of the Vitol prepaid fee related to the throughput capacity agreement for our Eagle North pipeline system of $2.2 million and interest of $0.2 million. This agreement matures at December 31, 2014.

(3) Represents required future payments under a non-compete agreement related to our acquisition of certain field services assets.

(4) 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 May 3, 2013 we had $242.5 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 (i) the ABR (the highest of the administrative agent's prime rate, the federal funds rate plus 0.5%, or the one-month eurodollar rate (as defined in our credit agreement) plus 1.0%), plus an applicable margin that ranges from 3.0% to 3.5%, or (ii) the eurodollar rate plus an applicable margin that ranges from 4.0% to 4.5%, in each case depending on our consolidated total leverage ratio (as defined in our credit agreement).

During the three months ended March 31, 2013, our weighted average interest rate was 5.34%, including interest under the throughput capacity agreement with Vitol related to our Eagle North pipeline system and the amortization of debt issuance costs, resulting in interest expense of approximately $2.7 million.

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 March 31, 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 $2.4 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 March 31, 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 March 31, 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 March 31, 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:	May 8, 2013	By:	/s/ Alex G. Stallings Alex G. Stallings Chief Financial Officer and Secretary
Date:	May 8, 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	Third Amendment to Credit Agreement, dated as of March 4, 2013, among the Partnership, the lenders party thereto, and JPMorgan Chase Bank, N.A., as administrative agent (filed as Exhibit 10.1 to the Partnership's Current Report on Form 8-K, filed March 4, 2013, and incorporated herein by reference).
10.2##	First Amendment to Crude Oil Storage Services Agreement, dated to be effective as of March 1, 2013, by and between BKEP Crude, LLC and Vitol Inc. (filed as Exhibit 10.13 to the Partnership's Annual Report on Form 10-K for the year ended December 31, 2012 and filed March 14, 2013, and incorporated herein by reference).
10.3##	First Amendment to Crude Oil Storage Services Agreement, dated to be effective as of March 1, 2013, by and between BKEP Pipeline, LLC and Vitol Inc. (filed as Exhibit 10.38 to the Partnership's Annual Report on Form 10-K for the year ended December 31, 2012 and filed March 14, 2013, and incorporated herein by reference).
10.4##	First Amendment to Crude Oil Storage Services Agreement, dated to be effective as of March 1, 2013, by and between BKEP Pipeline, LLC and Vitol Inc. (filed as Exhibit 10.40 to the Partnership's Annual Report on Form 10-K for the year ended December 31, 2012 and filed March 14, 2013, and incorporated herein by reference).
10.5##	First Amendment to Crude Oil Storage Services Agreement, dated to be effective as of March 1, 2013, by and between BKEP Pipeline, LLC and Vitol Inc. (filed as Exhibit 10.42 to the Partnership's Annual Report on Form 10-K for the year ended December 31, 2012 and filed March 14, 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 March 31, 2013, formatted in XBRL (eXtensible Business Reporting Language): (i) Document and Entity Information; (ii) Consolidated Balance Sheets as of December 31, 2012 and March 31, 2013; (iii) Consolidated Statements of Operations for the three months ended March 31, 2012 and 2013 and 2012; (iv)Consolidated Statement of Changes in Partners' Capital for the three months ended March 31, 2013; (v) Consolidated Statements of Cash Flows for the three months

ended March 31, 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.

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