Blueknight Energy Partners, L.P.
Form 10-Q
August 07, 2012

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 June 30, 2012

OR

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

For the transition period from __________ to _________

Commission File Number 001-33503

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

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

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes 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 August 3, 2012, there were 30,159,958 Series A Preferred Units and 22,670,137 common units outstanding.

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

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

	As of December 31, 2011	As of June 30, 2012
		(unaudited)
ASSETS		
Current assets:		
Cash and cash equivalents	$1,239	$3,831
Accounts receivable, net of allowance for doubtful accounts of $476 for both dates	14,191	11,636
Receivables from related parties, net of allowance for doubtful accounts of $0 for both dates	4,397	2,505
Prepaid insurance	1,725	3,223
Assets held for sale	603	1,434
Other current assets	1,838	3,151
Total current assets	23,993	25,780
Property, plant and equipment, net of accumulated depreciation of $135,302 and $144,086 at December 31, 2011 and June 30, 2012, respectively	266,355	261,320
Goodwill	7,216	7,216
Debt issuance costs, net	5,000	4,112
Intangibles and other assets, net	2,191	1,922
Total assets	$304,755	$300,350
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$10,138	$4,522
Accrued loss contingency	1,090	—
Accrued interest payable	231	213
Accrued interest payable to related parties	362	179
Accrued property taxes payable	1,813	1,995
Unearned revenue	790	3,752
Unearned revenue with related parties	1,149	1,640
Accrued payroll	5,226	4,030
Other accrued liabilities	3,740	4,602
Current portion of long-term payable to related parties	1,636	1,754
Total current liabilities	26,175	22,687
Long-term payable to related parties	2,681	1,773
Other long-term liabilities	100	186
Long-term debt (including $15.0 million with related parties for both dates)	218,000	215,000
Commitments and contingencies (Notes 5 and 13)		
Partners' capital:		
Series A Preferred Units (30,159,958 units issued and outstanding for both dates)	202,746	204,599
	465,483	466,474

Common unitholders (22,657,638 and 22,670,137 units issued and outstanding at December 31, 2011 and June 30, 2012, respectively)		
General partner interest (2.1% with 1,127,755 general partner units outstanding for both dates)	(610,430)	(610,369)
Total Partners' capital	57,799	60,704
Total liabilities and Partners' capital	$304,755	$300,350

See accompanying notes to unaudited consolidated financial statements.

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

	Three months ended June 30,		Six months ended June 30,	
	2011	2012	2011	2012
	(unaudited)			
Service revenue:				
Third party revenue	$32,670	$32,912	$64,624	$66,046
Related party revenue	10,421	10,846	19,990	22,288
Total revenue	43,091	43,758	84,614	88,334
Expenses:				
Operating	30,182	30,518	58,819	59,806
General and administrative	4,777	4,386	9,386	9,489
Total expenses	34,959	34,904	68,205	69,295
Gain on sale of assets	687	263	710	5,219
Operating income	8,819	9,117	17,119	24,258
Other (income) expenses:				
Interest expense	9,112	2,897	18,164	5,968
Change in fair value of embedded derivative within convertible debt	3,431	—	(4,866)	—
Change in fair value of rights offering liability	1,544	—	6,386	—
Income (loss) before income taxes	(5,268)	6,220	(2,565)	18,290
Provision for income taxes	77	73	147	149
Net income (loss)	$(5,345)	$6,147	$(2,712)	$18,141
Allocation of net income (loss) for calculation of earnings per unit:				
General partner interest in net income (loss)	$(46)	$186	$111	$493
Preferred interest in net income	$2,975	$5,391	$8,149	$10,782
Beneficial conversion feature attributable to preferred units	$11,021	$—	$21,920	$1,853
Income (loss) available to limited partners	$(19,295)	$570	$(32,892)	$5,013
Basic and diluted net income (loss) per common unit	$(0.55)	$0.02	$(0.94)	$0.22
Basic and diluted net income (loss) per subordinated unit	$(0.55)	$—	$(0.94)	$—
Weighted average common units outstanding - basic and diluted	21,890	22,670	21,890	22,665
Weighted average subordinated units outstanding - basic and diluted	12,571	—	12,571	—

See accompanying notes to unaudited consolidated financial statements.

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

	Common Unitholders	Series A Preferred Unitholders	General Partner Interest	Total Partners' Capital
	(unaudited)			
Balance, December 31, 2011	$465,483	$202,746	$(610,430)	$57,799
Net income	7,300	10,462	379	18,141
Equity-based incentive compensation	653	—	14	667
Amortization of beneficial conversion feature of Preferred units	(1,853)	1,853	—	—
Distributions	(5,109)	(10,462)	(332)	(15,903)
Balance, June 30, 2012	$466,474	$204,599	$(610,369)	$60,704

See accompanying notes to unaudited consolidated financial statements.

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

	Six months ended June 30,	
	2011	2012
	(unaudited)	
Cash flows from operating activities:		
Net income (loss)	$(2,712)	$18,141
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation and amortization	11,415	11,382
Amortization and write-off of debt issuance costs	966	888
Amortization of subordinated debenture discount	8,756	—
Change in fair value of embedded derivative within convertible debt	(4,866)	—
Change in fair value of rights offering liability	6,386	—
Asset impairment charge	—	1,073
Gain on sale of assets	(710)	(5,219)
Equity-based incentive compensation	209	667
Changes in assets and liabilities		
Decrease (increase) in accounts receivable	(4,133)	2,555
Decrease (increase) in receivables from related parties	(222)	1,892
Decrease (increase) in prepaid insurance	(139)	309
Increase in other current assets	(249)	(1,312)
Decrease (increase) in other assets	1,037	(1)
Decrease in accounts payable	(1,210)	(2,718)
Decrease in accrued interest payable	(78)	(18)
Increase (decrease) in accrued interest payable to related parties	2,686	(183)
Increase (decrease) in accrued property taxes	(126)	182
Increase in unearned revenue	385	2,962
Increase (decrease) in unearned revenue from related parties	(2,105)	491
Increase (decrease) in accrued payroll	609	(1,196)
Decrease in other accrued liabilities	(145)	(1,188)
Net cash provided by operating activities	15,754	28,707
Cash flows from investing activities:		
Acquisitions	(133)	—
Capital expenditures	(9,298)	(13,179)
Proceeds from sale of assets	752	7,291
Net cash used in investing activities	(8,679)	(5,888)
Cash flows from financing activities:		
Payment on insurance premium financing agreement	(342)	(534)
Debt issuance costs	(280)	—
Payments on long-term payable to related party	(447)	(790)
Borrowings under credit facility	6,000	24,000
Payments under credit facility	(5,862)	(27,000)
Distributions	(5,278)	(15,903)
Net cash used in financing activities	(6,209)	(20,227)
Net increase in cash and cash equivalents	866	2,592
Cash and cash equivalents at beginning of period	4,840	1,239
Cash and cash equivalents at end of period	$5,706	$3,831

Supplemental disclosure of cash flow information:		
Increase (decrease) in accounts payable related to purchase of property, plant and equipment	$472	$(2,898)
Increase in accrued liabilities related to insurance premium financing agreement	$1,278	$1,580

See accompanying notes to unaudited consolidated financial statements.

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

1. ORGANIZATION AND NATURE OF BUSINESS

Blueknight Energy Partners, L.P. (formerly SemGroup Energy Partners, L.P.) and subsidiaries (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 PRESENTATION

The financial statements have been prepared in accordance with accounting principles and practices generally accepted in the United States of America ("GAAP"). The consolidated statements of operations for the three and six months ended June 30, 2011 and 2012, the consolidated statement of changes in partners' capital for the six months ended June 30, 2012, the statement of cash flows for the six months ended June 30, 2011 and 2012, and the consolidated balance sheet as of June 30, 2012 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 2011 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, 2011 filed with the Securities and Exchange Commission (the "SEC") on March 13, 2012 (the "2011 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 our 2011 Form 10-K. A reclassification has been made in the consolidated financial statements for the three and six months ended June 30, 2011 to conform to the 2012 financial statement presentation. This was a reclassification of gain on sale of assets from operating expenses to a separate component of operating income. The reclassification has no impact on net income.

3. RECENT EVENTS

On January 10, 2012, the Partnership announced the planned retirement of the Chief Executive Officer of Blueknight Energy Partners G.P., L.L.C., the Partnership's general partner (the "General Partner"), Mr. James Dyer, who will remain as Chief Executive Officer until his successor is appointed.

4. PROPERTY, PLANT AND EQUIPMENT

	Estimated Useful Lives (Years)	December 31, 2011	June 30, 2012
		(dollars in thousands)	
Land	N/A	$16,601	$16,355
Land improvements	10-20	5,671	5,589
Pipelines and facilities	5-30	152,733	155,451
Storage and terminal facilities	10-35	169,139	169,092
Transportation equipment	3-10	20,615	19,943
Office property and equipment and other	3-20	22,901	25,395
Pipeline linefill and tank bottoms	N/A	7,458	5,993
Construction-in-progress	N/A	6,539	7,588
Property, plant and equipment, gross		401,657	405,406
Accumulated depreciation		(135,302)	(144,086)
Property, plant and equipment, net		$266,355	$261,320

Depreciation expense for each of the three months ended June 30, 2011 and 2012 was $5.7 million, and depreciation expense for the six months ended June 30, 2011 and 2012 was $11.4 million and $11.3 million, respectively. In the three and six months ended June 30, 2012, the Partnership recorded asset impairment expense of $1.1 million related to its pipelines and facilities.

5. DEBT

On 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 August 3, 2012, approximately $200.0 million of term loan borrowings and $10.7 million of revolver borrowings and letters of credit were outstanding under the credit facility, leaving the Partnership with approximately $84.3 million available capacity for additional revolver borrowings and letters of credit under the credit facility. 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.

Until May 15, 2011, borrowings under the credit agreement bore 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 of 3.25%, or (ii) the eurodollar rate plus an applicable margin of 4.25%. After May 15, 2011, the applicable margin for loans accruing interest based on the ABR ranges from 3.0% to 3.5%, and the applicable margin for loans accruing interest based on the eurodollar rate 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.

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 (except for the consolidated interest coverage ratio, which builds to a four-quarter test).

The maximum permitted consolidated total leverage ratio is 4.50 to 1.00 for each future fiscal quarter. The minimum permitted consolidated interest coverage ratio (as defined in the credit agreement) is 3.00 to 1.00 for each future fiscal quarter.

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

- create, incur or assume liens;
- engage in mergers or acquisitions;
- repurchase the Partnership's equity, make distributions to unitholders and make certain other restricted payments;
- make investments;
- modify the terms of the convertible subordinated debentures (as defined below) and certain other indebtedness, or prepay certain indebtedness;
- engage in transactions with affiliates;
- enter into certain burdensome contracts;
- change the nature of the Partnership's business;
- enter into operating leases; and
- make certain amendments to the Partnership's partnership agreement.

At June 30, 2012, the Partnership's leverage ratio was 2.88 and the interest coverage ratio was 6.81. The Partnership was in compliance with all covenants of its credit agreement as of June 30, 2012.

The credit agreement permits the Partnership to make quarterly distributions of available cash (as defined in the Partnership's partnership agreement) to unitholders so long as: (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 4.00 to 1.00 for any future fiscal quarter. 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 6 for additional information regarding distributions.

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

- 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 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 ERISA events involving the Partnership or any of its subsidiaries, in excess of a threshold amount;
- bankruptcy or other insolvency events involving the Partnership or any of its subsidiaries; and

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- a change in 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 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 and six months ended June 30, 2011 was $0.5 million and $1.0 million, respectively, and for the three and six month periods ended June 30, 2012 was $0.4 million and $0.9 million, respectively. The Partnership did not capitalize any debt issuance costs in either period.

During the three and six months ended June 30, 2012, the weighted average interest rate under the credit agreement incurred by the Partnership was 5.28% and 5.39%, respectively, and the total weighted average interest rate, including interest associated with the ENPS Throughput Capacity Agreement (as defined below), was 5.45% and 5.56%, respectively, resulting in interest expense of approximately $2.9 million and $6.0 million, respectively.

In October 2010 the Partnership issued the convertible subordinated debentures in a private placement in the aggregate principal amount of $50.0 million. If not previously redeemed, the convertible subordinated debentures, including all outstanding principal and unpaid interest, would have converted to Preferred Units on December 31, 2011. Upon issuance, this conversion feature was considered an embedded derivative, which the Partnership was required to bifurcate and carry at its fair value each reporting period. In connection with the establishment of the conversion price for the Preferred Units following the special meeting of the Partnership's unitholders in September 2011, the conversion option was deemed to meet the scope exception for certain contracts involving an entity's own equity in ACS 815-Derivatives and Hedging, and, therefore, the Partnership reclassified the embedded derivative as partners' capital in the third quarter of 2011. The Partnership redeemed the convertible subordinated debentures on November 9, 2011.

Changes to the fair value of the embedded derivative are reflected on the Partnership's consolidated statements of operations as "Change in fair value of embedded derivative within convertible debt." The value of the embedded derivative was contingent on changes in the expected fair value of the Partnership's preferred units. The Partnership recorded other expense of $3.4 million and other income of $4.9 million due to the change in the fair value of this embedded derivative in the three and six months ended June 30, 2011, respectively.

In addition, the recording of the embedded derivative liability related to the convertible subordinated debentures resulted in the Partnership recording a $20.9 million debt discount on the convertible subordinated debentures. The debt discount was being amortized to interest expense through the mandatory conversion date of December 31, 2011 using the effective interest rate method until the redemption of the convertible subordinated debentures on November 9, 2011. Upon redemption, the remaining unamortized debt discount was considered in the calculation of a $2.4 million extinguishment gain, which was determined to represent a capital transaction and, therefore, was recorded as a capital contribution to the Partnership by the Partnership's general partner. For the purpose of calculating net income per limited partner unit, this amount was added back to net loss available to limited partners as it represents the recovery of a portion of the additional financing costs resulting from bifurcation of the conversion option and related discount on the convertible subordinated debentures. The Partnership recognized non-cash interest expense of $4.4 million and $8.8 million in the three and six months ended June 30, 2011, respectively, due to the amortization of the debt discount.

6. DISTRIBUTIONS

The Partnership did not make a cash distribution to its common unitholders from May 15, 2008 to February 13, 2012 due, in part, to the events of default that existed under its former credit agreement, restrictions under such credit agreement, and the uncertainty of its future cash flows relating to SemCorp's bankruptcy filings ("SemCorp" refers to SemGroup Corporation and its predecessors including SemGroup, L.P., subsidiaries and affiliates other than the Partnership and the General Partner during periods in which the Partnership and the General Partner were affiliated with SemGroup, L.P.). As a result of the approval of the Partnership Agreement Amendment Proposal (as defined in the Partnership's Proxy Statement dated July 28, 2011) on September 14, 2011, all cumulative common unit arrearages were eliminated. The Partnership's common unitholders will be required to pay taxes on their share of the Partnership's taxable income even though they did not receive a cash distribution for the quarters ended June 30, 2008 through September 30, 2011. The Partnership is currently allowed to make distributions to its unitholders in accordance with its debt 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. The Partnership resumed distributions for common units on February 14, 2012 for the quarter ended December 31, 2011.

On July 24, 2012, the board of directors of our General Partner (the "Board") approved a distribution of $0.17875 per Preferred Unit, or a total distribution of $5.4 million. The Partnership will pay this distribution on the preferred units on August 15, 2012 to Preferred Unitholders of record as of August 3, 2012.

In addition, the Partnership declared a cash distribution of $0.11 per unit on its outstanding common units. The distribution will be paid on August 15, 2012 to unitholders of record on August 3, 2012. The distribution is for the three months ended June 30, 2012. The total distribution to be paid will be approximately $2.6 million, with approximately $2.5 million and $0.1 million to be paid to the Partnership's common unitholders and general partner, respectively, and $0.1 million to be paid to phantom and restricted unitholders pursuant to awards granted under the Partnership's long-term incentive plan.

7. NET INCOME PER LIMITED PARTNER UNIT

For purposes of calculating earnings per unit, the excess of distributions over earnings or excess of earnings over distributions for each period are allocated to the 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 loss per common and subordinated unit (in thousands, except per unit data):

	Three months ended June 30,		Six months ended June 30,	
	2011	2012	2011	2012
Net income (loss)	$(5,345)	$6,147	$(2,712)	$18,141
General partner interest in net income (loss)	(46)	186	111	493
Preferred interest in net income	2,975	5,391	8,149	10,782
Beneficial conversion feature attributable to preferred units	11,021	—	21,920	1,853
Income (loss) available to limited partners	$(19,295)	$570	$(32,892)	$5,013
Basic and diluted weighted average number of units:				
Common units	21,890	22,670	21,890	22,665
Subordinated units[(1)]	12,571	—	12,571	—
Restricted and phantom units	457	633	343	516
Basic and diluted net income (loss) per common unit	$(0.55)	$0.02	$(0.94)	$0.22
Basic and diluted net income (loss) per subordinated unit[(1)]	$(0.55)	$—	$(0.94)	$—

(1)

On September 14, 2011, Vitol and Charlesbank transferred all of the Partnership's outstanding subordinated units to the Partnership and the Partnership canceled such subordinated units.

8. RELATED PARTY TRANSACTIONS

The Partnership provides crude oil gathering, transportation, terminalling and storage services to Vitol. For the three and six months ended June 30, 2011, the Partnership recognized revenues of $10.4 million and $20.0 million, respectively for services provided to Vitol. For the three and six months ended June 30, 2012, the Partnership recognized revenues of $10.8 million and $22.3 million, respectively for services provided to Vitol. As of June 30, 2012, the Partnership had receivables from Vitol of $2.5 million.

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. During the three and six months ended June 30, 2011, the Partnership received payments of $0.3 million and $0.9 million, respectively, pursuant to the Vitol Omnibus Agreement. During the six months ended June 30, 2012, the Partnership received payments of $0.1 million pursuant to the Vitol Omnibus Agreement. 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. 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 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 Partnership’s 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 and $2.2 million from Vitol with respect to services provided pursuant to the 2008 Vitol Storage Agreement for the three months ended June 30, 2011 and 2012, respectively. The Partnership earned revenues of approximately $6.6 million and $5.5 million from Vitol with respect to services provided pursuant to the 2008 Vitol Storage Agreement for the six months ended June 30, 2011 and 2012, respectively. 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 of 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. The Partnership generated revenues under this agreement of approximately $3.1 million and $2.9 million during the three months ended June 30, 2011 and 2012, respectively. The Partnership generated revenues under this agreement of approximately $6.2 million and $5.9 million during the six months ended June 30, 2011 and 2012, respectively. 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.

The Partnership entered into two 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, when the 2008 Vitol Storage Agreement expired according to its terms. The Partnership believes that the rates it charges Vitol under both of these agreements 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 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 one 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 June 1, 2013. The Partnership generated revenues under this agreement of approximately $0.5 million for each of the three and six months ended June 30, 2012.

Service revenues under the 2012 Vitol 6-month Storage Agreement are based on the 500,000 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 is from June 1, 2012 through December 1, 2012. The Partnership generated revenues under this agreement of approximately $0.2 million for each of the three and six months ended June 30, 2012.

Vitol Master Lease Agreement

In July of 2010, the Partnership and Vitol entered into a Master Agreement (the "Master Agreement") relating to the lease of certain vehicles by the Partnership from Vitol. Pursuant to the Master Agreement, the Partnership leased certain vehicles, including light duty trucks, tractors, tank trailers and bobtail tank trucks, from Vitol for periods ranging from 36 months to 84 months depending on the type of vehicle. The Partnership had the opportunity to purchase each vehicle at the end of the lease at the estimated residual value of such vehicle. Leases under the Master Agreement were accounted for as operating leases. During the three and six months ended June 30, 2011, the Partnership recorded expenses under this agreement of approximately $0.1 million and $0.3 million, respectively. The Master 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. In September of 2011, the Partnership entered into a new master lease agreement with an unrelated third party and terminated the Master Agreement with Vitol.

Vitol Throughput Capacity Agreement

In August of 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 of 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 June 30, 2012. In addition, if the payments made by Vitol in any contract year under the ENPS Throughput Agreement are in the aggregate less than $2.4 million, then Vitol will 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. The ENPS Throughput Agreement has a term that extends for four years after ENPS is completed and may be extended by mutual agreement of the parties for additional one-year terms. If the capacity on ENPS is unavailable for use by Vitol for more than 60 days, whether consecutive or nonconsecutive, during the term of the ENPS Throughput Agreement, then Vitol shall have the right to terminate the ENPS Throughput Agreement within six months after such lack of capacity. The Partnership has previously contracted to provide throughput services on ENPS to a third party and Vitol's rights to the capacity of ENPS are subordinate to the rights of such third party. In addition, for so long as a default by Vitol relating to payments under the ENPS Throughput Agreement has not occurred and is continuing, the Partnership will remit to Vitol any and all tariffs and deficiency payments received by the Partnership or its affiliates from such third party pursuant to its agreement with the Partnership. The ENPS Throughput Agreement was approved by the Board's conflicts committee in accordance with the Partnership's procedures for approval of related party transactions and the provisions of its partnership agreement.

During the three and six months ended June 30, 2011, the Partnership incurred interest expense under this agreement of approximately $0.2 million and $0.4 million, respectively. During the three and six months ended June 30, 2012, the Partnership incurred interest expense under this agreement of approximately $0.1 million and $0.3 million, respectively. The agreement has an effective annual interest rate of 14.1% and matures on December 31, 2014.

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 the three and six months ended June 30, 2012, Vitol received its pro rata portion of the interest payments in connection with being a lender under the credit agreement and received approximately $0.2 million and $0.3 million, respectively, in connection therewith.

9. LONG-TERM INCENTIVE PLAN

In July of 2007, the General Partner adopted the Blueknight Energy Partners G.P., L.L.C. Long-Term Incentive Plan (the “Plan”). The compensation committee of the Board administers the Plan. The Plan 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 Plan 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 Plan, 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. The phantom unit awards also include distribution equivalent rights (“DERs”).

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

In March 2011 and March 2012, grants for 299,900 and 351,300 phantom common units, respectively, were made, which vest on January 1, 2014 and January 1, 2015, 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 and $6.76 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 and $2.4 million, respectively, on their grant date, and the unrecognized estimated compensation cost at June 30, 2012 was $3.1 million, which will be recognized over the remaining vesting period. As of June 30, 2012, the Partnership expects approximately 87% of these awards will vest. The Partnership’s equity-based incentive compensation expense for the three and six months ended June 30, 2012 was $0.4 million and $0.7 million, respectively.

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

	Number of Units	Weighted Average Grant Date Fair Value
Nonvested at December 31, 2011	307,151	$8.17
Granted	351,300	6.76
Vested	10,000	8.25
Forfeited	17,600	7.89
Nonvested at June 30, 2012	630,851	$7.39

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 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 a$0.3 million for each of the three months ended June 30, 2011 and 2012 for discretionary contributions under the plan. The Partnership recognized expense of $0.7 million and $0.6 million for the six months ended June 30, 2011 and 2012, respectively, for discretionary contributions under the plan.

The Partnership may also make annual lump-sum contributions to the 401(k) Plan irrespective of the employee's contribution match. The Partnership may make a discretionary annual contribution in the form of profit sharing calculated as a percentage of an employee's eligible compensation. This contribution is retirement income under the qualified 401(k) Plan. Annual profit sharing contributions to the 401(k) Plan are submitted to and approved by the Board. The Partnership recognized expense of $0.2 million for each of the three months ended June 30, 2011 and 2012 for discretionary profit sharing contributions under the 401(k) Plan. The Partnership recognized expense of $0.4 million and $0.5 million for the six months ended June 30, 2011 and 2012, respectively, for discretionary profit sharing contributions under the 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, 2011 or June 30, 2012.

The fair value of the embedded derivative within the subordinated convertible debentures was derived using a valuation model and has been classified as Level 3. The valuation model used is a discounted cash flow model (income approach) that assumes future distribution payments by the Partnership and utilizes interest rates and credit spreads for subordinated debt to preferred equity to determine the fair value of the derivative embedded within the subordinated convertible debentures. The change in fair value of the derivative liability for the three and six months ended June 30, 2011 of \$3.4 million and \$4.9 million, respectively, is included in other (income) expense in the Partnership's consolidated statements of operations. In connection with the establishment of the conversion price for the Preferred Units following the special meeting of the Partnership's unitholders in September 2011, the number of Preferred Units issuable upon conversion of the subordinated convertible debentures was an amount equal to (i) the sum of the outstanding principal and any accrued and unpaid interest being converted, divided by (ii) 6.50. The establishment of the conversion rate resulted in the embedded derivative meeting the scope exception in ASC 815-15 – Embedded Derivatives, and, therefore, the Partnership reclassified the embedded derivative as partners' capital on September 14, 2011.

The fair value of the rights offering liability related to certain rights that have been offered to common unitholders under the approved Global Transaction Agreement was derived using a valuation model and has been classified as Level 3. The valuation model used is a probability-weighted model (income approach) and assumes the number of rights that are exercised as well as the expected fair value of the Preferred Units at the time such rights are exercised. The change in fair value of the rights offering liability for the three and six months ended June 30, 2011 of \$1.5 million and \$6.4 million, respectively, is included in other (income) expense in the Partnership's consolidated statements of operations.

The following table sets forth a reconciliation of changes in the fair value of the Partnership's financial liabilities classified as Level 3 in the fair value hierarchy (in thousands):

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	Measurements Using Significant Unobservable Inputs (Level 3)	
	For the Three Months Ended June 30, 2011	For the Six Months Ended June 30, 2011
Beginning Balance	$34,536	$37,991
Total gains or losses (realized/unrealized):		
Included in earnings	4,975	1,520
Included in other comprehensive income	—	—
Purchases, issuances, and settlements(1)	—	—
Transfers in and/or out of Level 3	—	—
Balance at June 30, 2011	$39,511	$39,511
The amount of total income for the period included in earnings attributable to the change in unrealized gains for liabilities still held at the reporting date	$4,975	$1,520

(1) As noted above, the Partnership reclassified the embedded derivative within subordinated convertible debentures to partners' capital as of September 14, 2011.

Fair Value of Other Financial Instruments

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

At June 30, 2012, the carrying values on the unaudited condensed consolidated balance sheets for cash and cash equivalents (classified as Level 1), accounts receivable and accounts payable approximate their fair value because of their short term nature.

Based on the borrowing rates currently available to the Partnership for credit agreement debt with similar terms and maturities and consideration of the Partnership's non-performance risk, long-term debt associated with the Partnership's credit agreement at June 30, 2012 approximates its fair value. The fair value of the Partnership's long-term debt was calculated using observable inputs (LIBOR for the risk free component) and unobservable company-specific credit spread information. As such, the Partnership considers this debt to be Level 3.

12. OPERATING SEGMENTS

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

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

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

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

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

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

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

	Crude Oil Terminalling and Storage Services	Crude Oil Pipeline Services	Crude Oil Trucking and Producer Field Services	Asphalt Services	Total
Three Months Ended June 30, 2011					
Service revenue					
Third party revenue	$2,859	$5,040	$10,594	$14,177	$32,670
Related party revenue	6,743	1,166	2,512	—	10,421
Total revenue for reportable segments	9,602	6,206	13,106	14,177	43,091
Operating expenses (excluding depreciation and amortization)	1,392	4,826	12,411	5,843	24,472
Operating margin (excluding depreciation and amortization)(1)	8,210	1,380	695	8,334	18,619
Total assets (end of period)	78,918	101,621	15,472	131,437	327,448
Three Months Ended June 30, 2012					
Service revenue					
Third party revenue	$3,087	$3,594	$11,702	$14,529	$32,912
Related party revenue	6,293	1,180	3,340	33	10,846
Total revenue for reportable segments	9,380	4,774	15,042	14,562	43,758
Operating expenses (excluding depreciation and amortization)	1,015	4,902	13,268	5,607	24,792
Operating margin (excluding depreciation and amortization)(1)	8,365	(128)	1,774	8,955	18,966
Total assets (end of period)	68,837	96,542	20,450	114,521	300,350
Six months ended June 30, 2011					
Service revenue					
Third party revenue	$5,375	$8,894	$22,464	$27,891	$64,624
Related party revenue	14,066	2,181	3,743	—	19,990
Total revenue for reportable segments	19,441	11,075	26,207	27,891	84,614
Operating expenses (excluding depreciation and amortization)	2,145	8,796	25,222	11,241	47,404
Operating margin (excluding depreciation and amortization)(1)	17,296	2,279	985	16,650	37,210
Total assets (end of period)	78,918	101,621	15,472	131,437	327,448
Six months ended June 30, 2012					
Service revenue					
Third party revenue	$5,731	$8,059	$24,480	$27,776	$66,046
Related party revenue	12,894	2,510	6,559	325	22,288
Total revenue for reportable segments	18,625	10,569	31,039	28,101	88,334
Operating expenses (excluding depreciation and amortization)	1,725	8,850	26,368	11,481	48,424
Operating margin (excluding depreciation and amortization)(1)	16,900	1,719	4,671	16,620	39,910
Total assets (end of period)	68,837	96,542	20,450	114,521	300,350

(1)

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

	Three months ended June 30,		Six months ended June 30,	
	2011	2012	2011	2012
Operating margin (excluding depreciation and amortization)	$18,619	$18,966	37,210	39,910
Depreciation and amortization	5,710	5,726	11,415	11,382
General and administrative expenses	4,777	4,386	9,386	9,489
Gain on sale of assets	687	263	710	5,219
Interest expense	9,112	2,897	18,164	5,968
Change in fair value of embedded derivative within convertible debt	3,431	—	(4,866)	—
Change in fair value of rights offering liability	1,544	—	6,386	—
Income (loss) before income taxes	$(5,268)	$6,220	$(2,565)	$18,290

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 assert claims against the General Partner for alleged failure to pay wages and breach of contract and seek to recover the alleged value of units in the total amount of approximately $1.3 million, plus additional damages and attorneys’ fees. The Partnership has 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 has appealed this ruling. On October 22, 2010, the General Partner was ordered to pay $0.2 million in attorneys’ fees. The Partnership has also appealed this order.

Koch Industries, Inc. (together with its subsidiaries, “Koch”), a previous owner of the Partnership’s asphalt facility located in Northumberland, Pennsylvania, has alleged that the Partnership has responsibility to assess the polychlorinated biphenyl (“PCB”) contamination at such facility although the contamination occurred prior to the Partnership becoming the owner of such facility. Koch claims that it was absolved of its responsibility to assess and clean up the site during SemCorp’s bankruptcy proceedings. The Partnership contends that Koch retained responsibility for such environmental issues and that SemCorp’s bankruptcy proceedings did not absolve Koch of these liabilities. On July 6, 2011, the Partnership filed an adversary complaint in connection with SemCorp’s bankruptcy cases against Koch seeking a declaration that SemCorp’s bankruptcy proceedings did not impact Koch’s responsibility to assess and clean the Northumberland site. A responsive pleading has been filed by Koch. The Partnership intends to vigorously defend against Koch’s allegation that the Partnership should be required to assess or clean up the PCB contamination.

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 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.

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 June 30, 2012 are presented below (dollars in thousands):

Deferred tax assets	
Difference in bases of property, plant and equipment	$1,161
Deferred tax asset	1,161
Less: valuation allowance	(1,161)
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 May 2011, the FASB issued ASU 2011-04, "Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and International Financial Reporting Standards (IFRS)," which provides a consistent definition of fair value and common requirements for measurement of and disclosure about fair value between GAAP and IFRS. This new guidance changes some fair value measurement principles and disclosure requirements. The Partnership adopted this guidance beginning with the Partnership's Quarterly Report for the period ended March 31, 2012, and the impact was not material.

In September 2011, the FASB issued ASU 2011-08, "Testing for Goodwill Impairment," which allows an entity to first assess qualitative factors to determine whether it is necessary to perform the two-step quantitative goodwill impairment test. Under these assessments, an entity would not be required to calculate the fair value of a reporting unit unless the entity determines, based on a qualitative assessment, that it is more likely than not that its fair value is less than its carrying amount. The Partnership adopted this guidance beginning in its December 31, 2011 annual impairment test, and the impact was not material.

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 plans to adopt this guidance beginning in its December 31, 2012 annual impairment test, and does not anticipate the impact to be material.

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16. SUBSEQUENT EVENTS

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.

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. (f/k/a/ SemGroup 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, 2011, which was filed with the Securities and Exchange Commission (the "SEC") on March 13, 2012 (the "2011 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 2011 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.

Our Revenues

Our revenues consist of (i) terminalling and storage revenues, (ii) gathering, transportation and producer field services revenues and (iii) fuel surcharge revenues. For the three months ended June 30, 2012, we derived approximately 25% of our revenues from services we provided to Vitol, with the remainder of our services being provided to third parties.

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

As of August 3, 2012, we have approximately 5.8 million barrels of crude oil storage under service contracts with remaining terms ranging from month-to-month to 34 months, including 3.5 million barrels under contract to Vitol. As of August 3, 2012, we had 1.6 million barrels of crude oil storage with terms expiring in 2012 and an additional 0.4 million barrels of crude oil storage with month-to-month terms. Effective September 1, 2012, we will have contracted 0.6 million of the 1.6 million barrels of crude oil storage expiring in 2012 with contracts extending into 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.

We have long-term contracts in place for 42 of our 44 asphalt facilities. The majority of the leases and storage agreements related to these facilities have terms that expire at or near the end of 2016. We operate the asphalt facilities pursuant to the storage agreements while our contract counterparties operate the asphalt facilities that are subject to the lease agreements.

Gathering and transportation services revenues consist of service fees recognized for the gathering of crude oil for our customers and the transportation of crude oil to refiners, to common carrier pipelines for ultimate delivery to refiners, or to terminalling and storage facilities owned by us and others. Revenue for the gathering and transportation of crude oil is recognized when the service is performed and is based upon regulated and non-regulated tariff rates and the related transport volumes. Producer field services revenue consists of a number of services ranging from gathering condensates from natural gas producers to hauling produced water to disposal wells. Revenue for producer field services is recognized when the service is performed. We earn gathering and transportation revenues in two of our segments: (i) crude oil pipeline services, and (ii) crude oil trucking and producer field services.

During the three months ended June 30, 2012, we transported approximately 67 thousand barrels per day on our pipelines, of which Vitol consists of 27% of volumes transported. Additionally, since the beginning of 2012, we have been evaluating our gathering systems located in Oklahoma to determine whether or not they are economically feasible to continue to operate after taking into consideration transported volumes, ongoing maintenance costs and risk. As a result we have idled approximately 100 miles of gathering pipeline that we have determined not economically viable, and, as a result, we recognized a $1.0 million impairment charge related to these assets in three months ended June 30, 2012. The significant majority of any volumes that were displaced as a result of idling the pipeline has been retained by our crude oil transport trucks. We do not anticipate the idling of this gathering pipeline to have a significant impact on the overall future results of our operations.

As of June 30, 2012, we were transporting approximately 49 thousand barrels per day on our crude transport trucks, of which Vitol consists of approximately 32% of volumes transported. 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 for the remainder of 2012. 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 the 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 and general and administrative expenses related to our business remained relatively consistent during the first six months of 2012 as compared to the same period in 2011, and we expect to incur a similar level of expenses in the second half of 2012. We currently anticipate maintenance capital expenditures to be approximately $15.0 million to $17.0 million in 2012, of which we have spent $5.9 million as of June 30, 2012. Our interest expense decreased by $6.2 million during the three months ended June 30, 2012 as compared to the three months ended June 30, 2011 primarily as a result of our redeeming $50.0 million of subordinated convertible debentures with proceeds from the rights offering conducted in the fourth quarter of 2011 and the impact of non-cash interest expense due to the amortization of the associated debt discount incurred in 2011.

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 and the net operating loss ("NOL") carryforwards result in deferred tax assets and liabilities, which are included in our consolidated balance sheet. We must then assess, using all available positive and negative evidence, the likelihood that the deferred tax assets will be recovered from future taxable income. If we believe that recovery is not likely, we must establish a valuation allowance. To the extent we establish a valuation allowance or increase or decrease this allowance in a period, we must include an expense or reduction of expense within the tax provisions in the consolidated statement of operations.

Under ASC 740 – Accounting for Income Taxes, an enterprise must use judgment in considering the relative impact of negative and positive evidence. The weight given to the potential effect of negative and positive evidence should be commensurate with the extent to which it can be objectively verified. The more negative evidence that exists (a) the more positive evidence is necessary and (b) the more difficult it is to support a conclusion that a valuation allowance is not needed for some portion, or all of the deferred tax asset. Among the more significant types of evidence that we consider are:

- taxable income projections in future years,
- whether the carryforward period is so brief that it would limit realization of tax benefits,
- future revenue and operating cost projections that will produce more than enough taxable income to realize the deferred tax asset based on existing service rates and cost structures, and
- our earnings history exclusive of the loss that created the future deductible amount coupled with evidence indicating that the loss is an aberration rather than a continuing condition.

Given that our subsidiary that is taxed as a corporation has limited earnings history for purposes of determining the likelihood of realizing the benefits of the deferred tax assets, we have provided a full valuation allowance against our deferred tax asset as of June 30, 2012.

Distributions

We did not make a distribution to our common unitholders or subordinated unitholders from May 15, 2008 to 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 31, 2011. We resumed distributions for common units on February 14, 2012 for the quarter ended December 31, 2011. The amount of distributions paid and the decision to make any distribution is determined by our General Partner's board of directors (the "Board"), which has broad discretion to establish cash reserves for the proper conduct of our business and for future distributions to our unitholders. In addition, our cash distribution policy is subject to restrictions on distributions under our credit facility.

On July 24, 2012, the Board approved a distribution of $0.17875 per Preferred Unit, or a total distribution of $5.4 million. We will pay this distribution on the preferred units on August 15, 2012 to Preferred Unitholders of record as of August 3, 2012.

In addition, we declared a cash distribution of $0.11 per unit on our outstanding common units. The distribution will be paid on August 15, 2012 to unitholders of record on August 3, 2012. The distribution is for the three months ended June 30, 2012. The total distribution to be paid will be approximately $2.6 million, with approximately $2.5 million and $0.1 million to be paid to the Partnership's common unitholders and general partner, respectively, and $0.1 million to be paid to phantom and restricted unitholders pursuant to awards granted under the Partnership's long-term incentive plan.

Vitol Storage Agreements

On June 1, 2012, the crude oil storage services agreement with Vitol 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 one 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 June 1, 2013. Service revenues under the second agreement are based on the 500,000 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 is from June 1, 2012 through December 1, 2012.

Results of Operations

The table below summarizes our financial results for the three and six months ended June 30, 2011 and 2012:

	Three months ended June 30,		Six months ended June 30,	
	2011	2012	2011	2012
	(in thousands)			
Service revenues:				
Crude oil terminalling and storage revenues:				
Third party	$2,859	$3,087	$5,375	$5,731
Related party	6,743	6,293	14,066	12,894
Total crude oil terminalling and storage	9,602	9,380	19,441	18,625
Crude oil pipeline services revenues:				
Third party	5,040	3,594	8,894	8,059
Related party	1,166	1,180	2,181	2,510
Total crude oil pipeline services revenues	6,206	4,774	11,075	10,569
Crude oil trucking and producer field services revenues:				
Third party	10,594	11,702	22,464	24,480
Related Party	2,512	3,340	3,743	6,559
Total crude oil trucking and producer field services revenues:	13,106	15,042	26,207	31,039
Asphalt services revenues:				
Third party	14,177	14,529	27,891	27,776
Related party	—	33	—	325
Total asphalt services	14,177	14,562	27,891	28,101
Total revenues	43,091	43,758	84,614	88,334
Operating expenses:				
Crude oil terminalling and storage	2,430	2,051	4,176	3,793
Crude oil pipeline services	6,031	6,194	11,208	11,397
Crude oil trucking and producer field services	12,838	13,644	26,130	27,089
Asphalt services	8,883	8,629	17,305	17,527
Total operating expenses	30,182	30,518	58,819	59,806
General and administrative expenses	4,777	4,386	9,386	9,489
Gain on sale of assets	687	263	710	5,219
Operating income:	8,819	9,117	17,119	24,258
Other (income) expense:				
Interest expense	9,112	2,897	18,164	5,968
Change in fair value of embedded derivative within convertible debt	3,431	—	(4,866)	—
Change in fair value of rights offering liability	1,544	—	6,386	—
Income tax expense	77	73	147	149
Net income (loss)	$(5,345)	$6,147	$(2,712)	$18,141

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Three Months Ended June 30, 2012 Compared to the Three Months Ended June 30, 2011

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 $1.4 million and $2.0 million for the three months ended June 30, 2012 and 2011, respectively, for fuel and power, property tax, and insurance expenses related to the operations of our liquid asphalt facilities, were $43.8 million for the three months ended June 30, 2012, compared to $43.1 million for the three months ended June 30, 2011, an increase of $0.7 million, or 1.6%.

Crude oil terminalling and storage revenue decreased by $0.2 million to $9.4 million for the three months ended June 30, 2012 compared to $9.6 million for the three months ended June 30, 2011 primarily as a result of lower renegotiated storage rates as well as a result of our dismantling two 55,000 barrel tanks in 2011.

Crude oil pipeline services revenue decreased by $1.4 million to $4.8 million for the three months ended June 30, 2012 compared to $6.2 million for the three months ended June 30, 2011. In the three months ended June 30, 2011, we earned approximately $1.4 million of revenue related to reimbursable pipeline expense projects while we did not have any material reimbursable pipeline projects during 2012.

Crude oil trucking and producer field services revenue increased by $1.9 million to $15.0 million for the three months ended June 30, 2012 compared to $13.1 million for the three months ended June 30, 2011. This increase is primarily the result of higher rates for the majority of our crude oil trucking service contracts that became effective August 1, 2011.

Our asphalt services revenue, including reimbursement of fuel and power, property tax and insurance premiums, increased by $0.4 million to $14.6 million for the three months ended June 30, 2012 compared to $14.2 million for the three months ended June 30, 2011. The increase was due to increased product throughput revenue of $1.0 million, and was partially offset by a decrease of $0.6 million in fuel and power recovery revenues related to lower expenses.

Operating expenses. Operating expenses were $30.5 million for the three months ended June 30, 2012, compared to $30.2 million for the three months ended June 30, 2011, an increase of $0.3 million, or 1%.

Crude oil terminalling and storage operating expenses decreased by $0.3 million to $2.1 million for the three months ended June 30, 2012 compared to $2.4 million for the three months ended June 30, 2011 due primarily to a decrease in repair and maintenance expenses.

Our crude oil pipeline services operating expenses increased by $0.2 million to $6.2 million for the three months ended June 30, 2012 compared to $6.0 million for the three months ended June 30, 2011. In the second quarter of 2012, we idled approximately 100 miles of gathering lines associated with our Mid-Continent pipeline system, and, as a result, we recognized a $1.0 million impairment charge related to these assets in three months ended June 30, 2012. In addition, compensation expense increased by $0.4 million as a result of a change in our vacation policy. Previously, employees vested in an entire fiscal year’s vacation on the first day of each year. Under our current policy, which became effective January 1, 2012, employees earn vacation ratably throughout the year. This has resulted in a change in the timing of our recognition of vacation expense. These increases were partially offset by a $1.3 million decrease in repair and maintenance in our pipeline segment for the three months ended June 30, 2012 compared to the three months ended June 30, 2011 due to reimbursable pipeline expense projects that occurred last year.

Our crude oil trucking and producer field services operating expenses increased by $0.8 million to $13.6 million for the three months ended June 30, 2012, compared to $12.8 million for the three months ended June 30, 2011. This increase is due to increases in compensation expense of $0.4 million primarily related to the change in our vacation policy noted above, repairs and maintenance of $0.2 million and vehicle rental expense of $0.1 million for the three months ended June 30, 2012 compared to the three months ended June 30, 2011. In addition, we recorded an asset impairment charge of $0.1 million in the three months ended June 30, 2012 in relation to certain logistics equipment we have elected to replace with alternative technology.

Our asphalt operating expenses were consistent at $8.6 million for the three months ended June 30, 2012 compared to $8.9 million for the three months ended June 30, 2011.

General and administrative expenses. General and administrative expenses decreased by $0.4 million, or 8%, to $4.4 million for the three months ended June 30, 2012, compared to $4.8 million for the three months ended June 30, 2011. This change is a result of a decrease of $0.7 million in legal and professional expenses offset by an increase of $0.3 million in compensation expense primarily related to the change in our vacation policy noted above. We currently anticipate our general and administrative expenses to remain relatively consistent for the remainder of 2012, however, the anticipated hiring of a new Chief Executive Officer and the ongoing employment of said officer will result in incremental expenses.

Gain on sale of assets. In the three months ended June 30, 2012, we had gains on the sale of assets of $0.3 million due to the sale of old equipment in our trucking and field services segment.

Interest expense. Interest expense represents interest on borrowings under our credit facility as well as amortization of debt issuance costs and the debt discount related to the subordinated convertible debentures that were redeemed in November of 2011. Interest expense decreased by $6.2 million to $2.9 million for the three months ended June 30, 2012 compared to $9.1 million for the three months ended June 30, 2011. This decrease is primarily due to non-cash interest expense related to the subordinated convertible debentures, including the related debt discount, of $5.6 million for the three months ended June 30, 2011 whereas we had no related expense for the three months ended June 30, 2012 due to the redemption of the subordinated convertible debentures in the fourth quarter of 2011. We also had a decrease of $0.2 million due to a decrease in the weighted average debt outstanding for the three months ended June 30, 2012 compared to the three months ended June 30, 2011.

Other (income) expense. Other (income)/expense for the three months ended June 30, 2011 included an increase of $1.5 million in the fair value of the rights offering liability and a decrease of $3.4 million in the fair value of the embedded derivative liability derived from the conversion option in the subordinated convertible debentures.

Six Months Ended June 30, 2012 Compared to the Six Months Ended June 30, 2011

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 for fuel and power, property tax, and insurance expenses related to the operations of our liquid asphalt facilities of $2.8 million and $3.5 million for the six months ended June 30, 2012 and 2011, respectively, were $88.3 million for the six months ended June 30, 2012, compared to $84.6 million for the six months ended June 30, 2011, an increase of $3.7 million or 4%.

Crude oil terminalling and storage revenue decreased by $0.8 million to $18.6 million for the six months ended June 30, 2012 compared to $19.4 million for the six months ended June 30, 2011 as a result of renegotiated storage rates which were lower as well as a result of our dismantling two 55,000 barrel tanks in 2011.

Crude oil pipeline services revenue decreased by $0.5 million to $10.6 million for the six months ended June 30, 2012 compared to $11.1 million for the six months ended June 30, 2011. In the six months ended June 30, 2011, we earned approximately $1.4 million of revenue related to reimbursed pipeline expense projects while we did not have any reimbursable projects during 2012. This decrease is offset by additional revenue as a result of increased utilization of our pipeline services assets.

Crude oil trucking and producer field services revenue increased by $4.8 million to $31.0 million for the six months ended June 30, 2012 compared to $26.2 million for the six months ended June 30, 2011. This increase is primarily the result of higher rates for the majority of our crude oil trucking service contracts that became effective August 1, 2011.

Our asphalt services revenue, including reimbursement of fuel and power, property tax and insurance premiums, increased by $0.2 million to $28.1 million for the six months ended June 30, 2012 compared to $27.9 million for the six months ended June 30, 2011. The increase was due to increased product throughput revenue of $1.0 million, and was partially offset by a decrease of $0.7 million in fuel and power recovery revenues related to lower expenses.

Operating expenses.   Operating expenses were $59.8 million for the six months ended June 30, 2012, compared to $58.8 million for the six months ended June 30, 2011, an increase of $1.0 million, or 2%.

Crude oil terminalling and storage operating expenses decreased $0.4 million to $3.8 million for the six months ended June 30, 2012 compared to $4.2 million for the six months ended June 30, 2011 primarily due to a decrease in maintenance and repair expense.

Our crude oil pipeline services operating expenses increased $0.2 million to $11.4 million for the six months ended June 30, 2012 compared to $11.2 million for the six months ended June 30, 2011. In the second quarter of 2012, we idled approximately 100 miles of gathering lines associated with our Mid-Continent pipeline system, and, as a result, we recognized a $1.0 million impairment charge related to these assets in six months ended June 30, 2012. In addition, compensation expense increased by $0.6 million as a result of a change in our vacation policy. Previously, employees vested in an entire fiscal year's vacation on the first day of each year. Under our current policy, which became effective January 1, 2012, employees earn vacation ratably throughout the year. This has resulted in a change in the timing of our recognition of vacation expense. These increases were partially offset by a $1.4 million decrease in repair and maintenance expense in our pipeline segment for the six months ended June 30, 2012 compared to the six months ended June 30, 2011 due to reimbursable pipeline expense projects that occurred last year.

Our crude oil trucking and producer field services operating expenses increased by $1.0 million to $27.1 million for the six months ended June 30, 2012, compared to $26.1 million for the six months ended June 30, 2011. Compensation expense increased $0.5 million, fuel costs increased $0.2 million, and vehicle rent expense increased $0.2 million for the six months ended June 30, 2012 compared to the six months ended June 30, 2011. All of these increases are primarily the result of increased utilization of our trucking and producer field services assets.

Our asphalt operating expenses increased by $0.2 million to $17.5 million for the six months ended June 30, 2012 compared to $17.3 million for the six months ended June 30, 2011. We incurred an incremental $0.7 million in maintenance and repair expenses in the six months ended June 30, 2012 compared to the six months ended June 30, 2011 as a result of a tank inspection program that we implemented in the first quarter of 2011 in response to new regulation of the asphalt industry. We also incurred additional compensation costs of $0.4 million for the six months ended June 30, 2012. These increases were offset by decreases in utilities expense of $0.6 million due to a decrease in fuel expenses.

General and administrative expenses. General and administrative expenses increased by $0.1 million, or 1%, to $9.5 million for the six months ended June 30, 2012, compared to $9.4 million for the six months ended June 30, 2011. We currently anticipate our general and administrative expenses to remain relatively consistent for the remainder of 2012, however, the anticipated hiring of a new Chief Executive Officer and the ongoing employment of said officer will result in incremental expenses.

Gain on sale of assets. In the six months ended June 30, 2012, we had gains on the sale of assets of $5.2 million. The gains are primarily a result of the sale of 60,000 barrels of excess crude oil linefill attributed to our Longview pipeline system in East Texas. The linefill was sold to Vitol for the market price for East Texas crude of $98.96 per barrel. This transaction resulted in a gain of approximately $4.5 million.

Interest expense. Interest expense represents interest on borrowings under our credit facility as well as amortization of debt issuance costs and the debt discount related to the subordinated convertible debentures that were redeemed in November of 2011. Interest expense decreased by $12.2 million to $6.0 million for the six months ended June 30, 2012 compared to $18.2 million for the six months ended June 30, 2011. This decrease is primarily due to non-cash interest expense related to the subordinated convertible debentures, including the related debt discount, of $11.3 million for the six months ended June 30, 2011 whereas we had no related expense for the six months ended June 30, 2012 due to the redemption of the subordinated convertible debentures in the fourth quarter of 2011. We also had a decrease of $0.4 million due to a decrease in the weighted average debt outstanding for the six months ended June 30, 2012 compared to the six months ended June 30, 2011.

Other (income) expense. Other (income)/expense for the six months ended June 30, 2011 included a decrease of $4.9 million in the fair value of the rights offering liability and a decrease of $6.4 million in the fair value of the embedded derivative liability derived from the conversion option in the subordinated convertible debentures.

Effects of Inflation

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

Off Balance Sheet Arrangements

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

Liquidity and Capital Resources

Cash Flows and Capital Expenditures

The following table summarizes our sources and uses of cash for the six months ended June 30, 2011 and 2012:

	Six months ended June 30,	
	2011	2012
	(in millions)	
Net cash provided by operating activities	$15.8	$28.7
Net cash used in investing activities	(8.7)	(5.9)
Net cash used in financing activities	(6.2)	(20.2)

Operating Activities. Net cash provided by operating activities was $28.7 million for the six months ended June 30, 2012, as compared to $15.8 million for the six months ended June 30, 2011. The increase in net cash provided by operating activities is primarily due to an increase in net income of $20.9 million for the six months ended June 30, 2012 compared to the six months ended June 30, 2011. The increase in net income was primarily the result of $12.2 million less interest expense as a result of redeeming the subordinated convertible debentures in the fourth quarter of 2011 in addition to an increase in gains on the sale of assets of $4.5 million.

Investing Activities. Net cash used in investing activities was $5.9 million for the six months ended June 30, 2012, as compared to $8.7 million of net cash used for the six months ended June 30, 2011. The decrease in cash used in investing activities was primarily the result of an increase of $6.5 million in proceeds from the sale of assets in the six months ended June 30, 2012 and was offset by a $3.9 million increase in capital expenditures.

Financing Activities. Net cash used in financing activities was $20.2 million for the six months ended June 30, 2012, as compared to $6.2 million for the six months ended June 30, 2011. The increase in net cash used in financing activities for the six months ended June 30, 2012 is primarily the result of $15.9 million of distributions to our unitholders and an increase in net repayments on long term debt of $3.1 million.

Our Liquidity and Capital Resources

Cash flow from operations and our credit facility are our primary sources of liquidity. At June 30, 2012, we had approximately $79.3 million of availability under our revolving credit facility and working capital of $3.1 million. On April 5, 2011, our revolving credit facility was increased from $75.0 million to $95.0 million. As of August 3, 2012, we have aggregate unused credit availability under our revolving credit facility of approximately $84.3 million and cash on hand of approximately $4.6 million.

Capital Requirements. Our capital requirements consist of the following:

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

Expansion capital expenditures for organic growth projects totaled $7.3 million in the six months ended June 30, 2012, compared to $4.3 million in the six months ended June 30, 2011. We expect expansion capital expenditures for organic growth projects to be approximately $45.0 million to $50.0 million in 2012. Maintenance capital expenditures totaled $5.9 million in the six months ended June 30, 2012 compared to $5.0 million in the six months ended June 30, 2011. We expect maintenance capital expenditures to be approximately $15.0 million to $17.0 million in 2012.

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 expect that substantially all of our cash generated from operations will be used to reduce our debt or pay distributions. Accordingly, 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.

Through May 15, 2011, borrowings under our credit agreement bore 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 of 3.25%, or (ii) the eurodollar rate plus an applicable margin of 4.25%.

After May 15, 2011, the applicable margin for loans accruing interest based on the ABR ranges from 3.0% to 3.5%, and the applicable margin for loans accruing interest based on the eurodollar rate 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 and six months ended June 30, 2012, our weighted average interest rate was 5.45% and 5.56%, respectively, 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 $2.9 million and $6.0 million, respectively.

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 (except for the consolidated interest coverage ratio, which builds to a four-quarter test).

The maximum permitted consolidated total leverage ratio is 4.50 to 1.00 for the fiscal quarter ending June 30, 2012 and each fiscal quarter thereafter. The minimum permitted consolidated interest coverage ratio (as defined in our credit agreement) is 3.00 to 1.00 for the fiscal quarter ending June 30, 2012 and each fiscal quarter 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 the Convertible Debentures and certain other indebtedness, or prepay certain indebtedness;
- engage in transactions with affiliates;

- enter into certain hedging contracts;
- enter into certain burdensome agreements;
- change the nature of our business;
- enter into operating leases; and
- make certain amendments to our partnership agreement.

At June 30, 2012, our leverage ratio was 2.88 to 1.00 and the interest coverage ratio was 6.81 to 1.00. We were in compliance with all covenants of our credit agreement as of June 30, 2012.

The credit agreement permits 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 4.00 to 1.00 for any fiscal quarter ending on or after March 31, 2012. 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 ERISA events involving us or any of our subsidiaries, in excess of a threshold amount;
- bankruptcy or other insolvency events involving us or any of our subsidiaries; and
- a change in 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 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 June 30, 2012, is as follows:

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Contractual Obligations	Payments Due by Period Total	Less than 1 year	1-3 years	4-5 years	More than 5 years
	(in millions)				
Debt obligations[(1)]	$237.3	$9.6	$227.7	$—	$—
Operating lease obligations	14.8	4.9	6.5	2.0	1.4
Related party throughput capacity agreement[(2)]	4.0	2.1	1.9	—	—
Non-compete agreement[(3)]	0.2	0.1	0.1	—	—
Employee contract obligations[(4)]	0.2	0.1	0.1	—	—

(1) Represents required future principal repayments of borrowings of $215.0 million and variable rate interest payments of $22.3 million. At June 30, 2012, our borrowings had an interest rate of approximately 4.28%. 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 $3.5 million and interest of $0.5 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 to certain employees for long-term incentive rewards forfeited upon leaving their former employer.

Recent Accounting Pronouncements

For information regarding recent accounting developments that may affect our future financial statements, see Note 15 of the Notes to Unaudited Consolidated Financial Statements included in Part I, Item I of this quarterly report.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

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

As of August 3, 2012 we had $200.0 million outstanding under our credit facility that was subject to a variable interest rate. Until May 15, 2011, borrowings under our credit agreement bore 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 of 3.25%, or (ii) the eurodollar rate plus an applicable margin of 4.25%. After May 15, 2011, the applicable margin for loans accruing interest based on the ABR ranges from 3.0% to 3.5%, and the applicable margin for loans accruing interest based on the eurodollar rate 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 and six months ended June 30, 2012, our weighted average interest rate was 5.45% and 5.56%, respectively, 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 $2.9 million and $6.0 million, respectively.

Changes in economic conditions could result in higher interest rates, thereby increasing our interest expense and reducing our funds available for capital investment, operations or distributions to our unitholders. Based on borrowings as of June 30, 2012 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 $2.2 million.

Item 4. Controls and Procedures

Evaluation of disclosure controls and procedures. Our General Partner’s management, including the Chief Executive Officer and Chief Financial Officer of our General Partner, evaluated as of the end of the period covered by this report, the effectiveness of our disclosure controls and procedures as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer of our General Partner concluded that our disclosure controls and procedures, as of June 30, 2012, were effective.

Changes in internal control over financial reporting. There were no changes in our internal control over financial reporting that occurred during the three months ended June 30, 2012 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 5. Other Information
Shared Services Agreement

Effective August 1, 2012, we entered into a new shared services agreement (the “Shared Services Agreement”) with Vitol under which we will provide Vitol with strategic assessment, economic evaluation and project design services for certain Vitol petroleum-based projects. In consideration of our provision of the services, Vitol will pay a monthly retainer fee as well as a project fee for each project approved by Vitol's board of directors. Vitol will also pay a onetime fee of $320,000 for services for the Foundation Pipeline in West Texas. The Shared Services Agreement renews annually unless terminated by either party as provided in the agreement.

The foregoing description is a summary of the Shared Services Agreement and is qualified in its entirety by reference to the Shared Services Agreement, a copy of which is included as Exhibit 10.3 to this Quarterly Report on Form 10-Q.

Vitol Storage Agreement

On August 3, 2012, we entered into a new crude oil storage services agreement with Vitol under which we will provide additional crude oil storage services to Vitol effective September 1, 2012. Service revenues under the agreement are based on the 500,000 barrels of storage capacity of the crude oil storage tanks that are dedicated to Vitol under the service agreement. The initial term of the agreement is from September 1, 2012 through February 1, 2013.
The foregoing description is a summary of the storage agreement with Vitol and is qualified in its entirety by reference to the storage agreement with Vitol, a copy of which is included as Exhibit 10.4 to this Quarterly Report on Form 10-Q.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

For a discussion of certain litigation and similar proceedings, please refer to Note 13, “Commitments and Contingencies,” and Note 16, “Subsequent Events,” of the Notes to Unaudited Consolidated Financial Statements, which is incorporated by reference herein.

Item 1A. Risk Factors

Information about risk factors for the three months ended June 30, 2012 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, 2011.

Item 6. Exhibits

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

SIGNATURES

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

			BLUEKNIGHT ENERGY PARTNERS, L.P.
		By:	Blueknight Energy Partners, G.P., L.L.C its General Partner
Date:	August 7, 2012	By:	/s/ Alex G. Stallings Alex G. Stallings Chief Financial Officer and Secretary
Date:	August 7, 2012	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	Crude Oil Storage Services Agreement, dated to be effective as of June 1, 2012, by and between BKEP Pipeline, LLC and Vitol Inc. (filed as Exhibit 10.1 to the Partnership's Quarterly Report on Form 10-Q for the quarter ended March 31, 2012, filed May 9, 2012, and incorporated herein by reference).
10.2	Crude Oil Storage Services Agreement, dated to be effective as of June 1, 2012, by and between BKEP Pipeline, LLC and Vitol Inc. (filed as Exhibit 10.2 to the Partnership's Quarterly Report on Form 10-Q for the quarter ended March 31, 2012, filed May 9, 2012, and incorporated herein by reference).
10.3*	Shared Services Agreement, dated to be effective as of August 1, 2012, by and between the Partnership and Vitol Inc.
10.4*##	Crude Oil Storage Services Agreement, dated to be effective as of September 1, 2012, by and between BKEP Pipeline, LLC and Vitol Inc.
31.1*	Certifications of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certifications of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C., Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. Pursuant to SEC Release 34-47551, this Exhibit is furnished to the SEC and shall not be deemed to be "filed."
101#	The following financial information from Blueknight Energy Partners, L.P.'s Annual Report on Form 10-Q for the quarter ended June 30, 2012, formatted in XBRL (eXtensible Business Reporting Language): (i) Document and Entity Information; (ii) Consolidated Balance Sheets as of December 31, 2011 and June 30, 2012; (iii) Consolidated Statements of Operations for the three and six months ended June 30, 2011 and 2012; (iv)Consolidated Statement of Changes in Partners' Capital for the six months ended June 30, 2012; (v) Consolidated Statements of Cash Flows for the six months ended June 30, 2011 and 2012; 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.