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

Form 10-Q

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

for the quarterly period ended September 30, 2013

OR

☐ **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: 000-50067

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

Delaware	**16-1616605**
(State of organization)	(I.R.S. Employer Identification No.)
2501 CEDAR SPRINGS	
DALLAS, TEXAS	**75201**
(Address of principal executive offices)	(Zip Code)

(214) 953-9500
(Registrant's telephone number, including area code)

Indicate by check mark whether 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 ☒ No ☐

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 ☒ No ☐

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 ☒	Accelerated filer ☐
Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

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

As of October 25, 2013, the Registrant had 90,135,937 common units outstanding.

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CROSSTEX ENERGY, L.P.

Condensed Consolidated Balance Sheets

	September 30, 2013	December 31, 2012
	(Unaudited)	
	(In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 9	$ 124
Accounts receivable:		
Trade, net of allowance for bad debt of $520 and $535, respectively	82,072	63,690
Accrued revenue and other	123,612	155,720
Fair value of derivative assets	1,110	3,234
Natural gas and natural gas liquids inventory, prepaid expenses and other	20,309	11,853
Assets held for disposition	—	22,599
Total current assets	227,112	257,220
Property and equipment, net of accumulated depreciation of $573,701 and $503,867, respectively	1,791,619	1,471,248
Intangible assets, net of accumulated amortization of $219,056 and $263,305, respectively	320,804	425,005
Goodwill	153,802	152,627
Investment in limited liability company	99,561	90,500
Other assets, net	23,456	25,989
Total assets	$ 2,616,354	$ 2,422,589
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable, drafts payable and other	$ 29,927	$ 32,265
Accrued gas and crude oil purchases	127,325	140,344
Fair value of derivative liabilities	600	1,310
Other current liabilities	82,349	71,340
Accrued interest	14,936	26,712
Liabilities held for disposition	—	3,572
Total current liabilities	255,137	275,543
Long-term debt	1,042,728	1,036,305
Other long-term liabilities	27,889	30,256
Deferred tax liability	65,907	71,404
Fair value of derivative liabilities	19	—
Commitments and contingencies	—	—
Partners' equity	1,224,674	1,009,081
Total liabilities and partners' equity	$ 2,616,354	$ 2,422,589

See accompanying notes to condensed consolidated financial statements.

CROSSTEX ENERGY, L.P.

Condensed Consolidated Statements of Operations

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012 (As Adjusted)	2013	2012 (As Adjusted)
	(Unaudited) (In thousands, except per unit amounts)			
Revenues	$ 468,362	$ 444,947	$ 1,368,640	$ 1,265,308
Operating costs and expenses:				
Purchased gas, NGLs and crude oil	368,349	345,202	1,068,464	975,507
Operating expenses	39,090	35,551	113,204	93,928
General and administrative	15,605	16,470	50,053	44,398
(Gain) loss on sale of property	(270)	109	(175)	(395)
(Gain) loss on derivatives	1,634	759	1,662	(1,977)
Depreciation and amortization	33,205	45,059	101,566	110,107
Impairment	72,576	—	72,576	—
Total operating costs and expenses	530,189	443,150	1,407,350	1,221,568
Operating income (loss)	(61,827)	1,797	(38,710)	43,740
Other income (expense):				
Interest expense, net of interest income	(16,430)	(23,229)	(54,874)	(63,932)
Equity in income (loss) of limited liability company	(65)	1,511	(106)	1,511
Other income	38	4,439	368	4,464
Total other expense	(16,457)	(17,279)	(54,612)	(57,957)
Loss before non-controlling interest and income taxes	(78,284)	(15,482)	(93,322)	(14,217)
Income tax provision	(554)	(672)	(2,097)	(1,507)
Net loss	(78,838)	(16,154)	(95,419)	(15,724)
Less: Net loss attributable to the non-controlling interest	—	(54)	—	(163)
Net loss attributable to Crosstex Energy, L.P.	$ (78,838)	$ (16,100)	$ (95,419)	$ (15,561)
Preferred interest in net loss attributable to Crosstex Energy, L.P.	$ 8,286	$ 5,640	$ 23,497	$ 15,346
General partner interest in net loss	$ (1,451)	$ (309)	$ (3,007)	$ (420)
Limited partners' interest in net loss attributable to Crosstex Energy, L.P.	$ (85,673)	$ (21,431)	$ (115,909)	$ (30,487)
Net loss attributable to Crosstex Energy, L.P. per limited partners' unit:				
Basic and diluted per common unit	$ (0.95)	$ (0.34)	$ (1.38)	$ (0.53)

See accompanying notes to condensed consolidated financial statements.

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CROSSTEX ENERGY, L.P.

Consolidated Statements of Comprehensive Income (Loss)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(Unaudited) (In thousands)			
Net loss	$ (78,838)	$ (16,154)	$ (95,419)	$ (15,724)
Hedging gains reclassified to earnings	(448)	(593)	(939)	(168)
Adjustment in fair value of derivatives	(745)	(179)	262	1,578
Comprehensive loss	(80,031)	(16,926)	(96,096)	(14,314)
Comprehensive loss attributable to non-controlling interest	—	54	—	163
Comprehensive loss attributable to Crosstex Energy, L.P.	$ (80,031)	$ (16,872)	$ (96,096)	$ (14,151)

See accompanying notes to condensed consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Changes in Partners' Equity
Nine Months Ended September 30, 2013

	Common Units		Preferred Units		General Partner Interest		Accumulated Other Comprehensive Income (loss)	Total
	$	Units	$	Units	$	Units		
				(Unaudited) (In thousands)				
Balance, December 31, 2012	$ 832,529	66,743	$ 154,137	15,072	$ 21,784	1,553	$ 631	$ 1,009,081
Issuance of common units	389,186	22,975	—	—	—	—	—	389,186
Proceeds from exercise of unit options	737	133	—	—	—	—	—	737
Conversion of restricted units, net of units withheld for taxes	(1,928)	283	—	—	—	—	—	(1,928)
Stock-based compensation	5,534	—	—	—	5,544	—	—	11,078
Distributions	(82,303)	—	—	1,154	(5,080)	24	—	(87,383)
Net income (loss)	(115,909)	—	23,497	—	(3,007)	—	—	(95,419)
Hedging gains reclassified to earnings	—	—	—	—	—	—	(939)	(939)
Adjustment in fair value of derivatives	—	—	—	—	—	—	262	262
Balance, September 30, 2013	$ 1,027,846	90,134	$ 177,634	16,226	$ 19,241	1,577	$ (46)	$ 1,224,675

See accompanying notes to condensed consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Cash Flows

	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
	(Unaudited) (In thousands)	
Cash flows from operating activities:		
Net loss	$ (95,419)	$ (15,724)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation and amortization	101,566	110,107
Impairment	72,576	—
Gain on sale of property and other assets	(175)	(3,381)
Deferred tax benefit	(6,031)	(375)
Non-cash stock-based compensation	11,078	7,496
(Gain) loss on derivatives recognized in net loss	(1,662)	1,977
Cash received (paid) on derivatives not recognized as revenue	2,418	(7,500)
Amortization of debt issue costs	4,558	3,940
Amortization of discount on notes	1,423	1,423
Distribution of earnings from limited liability company	3,144	—
Equity in (income) loss from limited liability company	106	(1,511)
Changes in assets and liabilities:		
Accounts receivable, accrued revenue and other	12,548	(18,431)
Natural gas and natural gas liquids, prepaid expenses and other	(6,642)	(7,144)
Accounts payable, accrued gas and crude oil purchases and other accrued liabilities	(10,857)	(26,296)
Net cash provided by operating activities	88,631	44,581
Cash flows from investing activities:		
Additions to property and equipment	(397,354)	(141,319)
Acquisition of business	—	(212,521)
Proceeds from sale of property	18,459	11,677
Investment in limited liability company	(22,261)	(52,250)
Distribution from limited liability company in excess of earnings	9,951	—
Net cash used in investing activities	(391,205)	(394,413)
Cash flows from financing activities:		
Proceeds from borrowings	314,500	696,500
Payments on borrowings	(309,500)	(526,000)
Payments on capital lease obligations	(2,433)	(2,337)
Increase in drafts payable	1,306	4,319
Debt refinancing costs	(2,026)	(6,896)
Conversion of restricted units, net of units withheld for taxes	(1,928)	(1,030)
Issuance of common units	389,186	232,791
Distribution to partners	(87,383)	(72,947)
Proceeds from exercise of unit options	737	347
Contributions from general partner	—	3,460
Net cash provided by financing activities	302,459	328,207
Net decrease in cash and cash equivalents	(115)	(21,625)
Cash and cash equivalents, beginning of period	124	24,143
Cash and cash equivalents, end of period	$ 9	$ 2,518
Cash paid for interest	$ 78,334	$ 70,460
Cash paid for income taxes	$ 6,565	$ 953

See accompanying notes to condensed consolidated financial statements.

CROSSTEX ENERGY, L.P.

Notes to Condensed Consolidated Financial Statements

September 30, 2013
(Unaudited)

(1) General

Unless the context requires otherwise, references to "we," "us," "our" or the "Partnership" mean Crosstex Energy, L.P. and its consolidated subsidiaries.

Crosstex Energy, L.P., a Delaware limited partnership formed on July 12, 2002, is engaged in the gathering, processing, transmission and marketing to producers of natural gas, natural gas liquids ("NGLs") and crude oil. We also provide crude oil, condensate and brine services to producers. We connect the wells of natural gas producers in our market areas to our gathering systems, process natural gas for the removal of NGLs, fractionate NGLs into purity products and market those products for a fee, transport natural gas and ultimately provide natural gas to a variety of markets. We purchase natural gas from natural gas producers and other supply sources and sell that natural gas to utilities, industrial consumers, other marketers and pipelines. We operate processing plants that process gas transported to the plants by major interstate pipelines or from our own gathering systems under a variety of fee arrangements. In addition, we purchase natural gas from producers not connected to our gathering systems for resale and sell natural gas on behalf of producers for a fee. We provide a variety of crude services throughout the Ohio River Valley ("ORV") which include crude oil gathering via pipelines and trucks and oilfield brine disposal. We also have crude oil terminal facilities in south Louisiana that provide access for crude oil producers to the premium markets in this area.

Crosstex Energy GP, LLC (the "General Partner") is the general partner of the Partnership. Crosstex Energy GP, LLC is a direct, wholly-owned subsidiary of Crosstex Energy, Inc. ("CEI").

(a) Basis of Presentation

The accompanying condensed consolidated financial statements are prepared in accordance with the instructions to Form 10-Q, are unaudited and do not include all the information and disclosures required by generally accepted accounting principles in the United States of America ("US GAAP") for complete financial statements. All adjustments that, in the opinion of management, are necessary for a fair presentation of the results of operations for the interim periods have been made and are of a recurring nature unless otherwise disclosed herein. The results of operations for such interim periods are not necessarily indicative of results of operations for a full year. All significant intercompany balances and transactions have been eliminated in consolidation. Certain reclassifications have been made to the consolidated financial statements for the prior year to conform to the current presentation. These condensed consolidated financial statements should be read in conjunction with the consolidated financial statements and notes thereto included in the Partnership's annual report on Form 10-K for the year ended December 31, 2012.

The preparation of financial statements in accordance with US GAAP requires management of the Partnership to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from these estimates.

(b) Comprehensive Income (Loss)

Accumulated Other Comprehensive Income Reclassifications. In February 2013, the Financial Accounting Standards Board ("FASB") issued ASU 2013-2, *Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income* ("ASU 2013-2"). ASU 2013-2 requires disclosure of amounts reclassified out of accumulated other comprehensive income ("AOCI") by component. In addition, an entity is required to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of AOCI by the respective line items of net income but only if the amount reclassified is required to be reclassified to net income in its entirety in the same reporting period. For amounts not reclassified in their entirety to net income, an entity is required to cross-reference to other disclosures that provide additional detail about those amounts. For the three months ended September 30, 2013 and 2012, we reclassified cash flow hedge gains in the amounts of $0.4 million and $0.6 million, respectively, and $0.9 million and $0.2 million for the nine months ended September 30, 2013 and 2012, respectively, included in other comprehensive income to revenues on the condensed consolidated statement of operations.

(c) Intangible Asset Impairment

In August 2013, the Partnership shutdown the Eunice processing plant (the “Plant”), which is located in south Louisiana and is part of our PNGL segment, due to adverse economics driven by low NGL prices and low processing volumes which we do not see improving in the near future based on forecasted price curves. The Partnership recorded an impairment expense of $72.6 million during the third quarter of 2013 related to the intangible assets for the terminated customer relationships attributable to the Plant shut-down.

(d) Goodwill

Goodwill is the cost of an acquisition less the fair value of the net identifiable assets of the acquired business. The Partnership evaluates goodwill for impairment annually as of July 1, and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount. The Partnership first assesses qualitative factors to evaluate whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as the basis for determining whether it is necessary to perform the two-step goodwill impairment test. The Partnership may elect to perform the two-step goodwill impairment test without completing a qualitative assessment. If a two-step process goodwill impairment test is elected or required, the first step involves comparing the fair value of the reporting unit, to which goodwill has been allocated, with its carrying amount. If the carrying amount of a reporting unit exceeds its fair value, the second step of the process involves comparing the implied fair value to the carrying value of the goodwill for that reporting unit. If the carrying value of the goodwill of a reporting unit exceeds the implied fair value of that goodwill, the excess of the carrying value over the implied fair value is recognized as an impairment loss. There were no impairment charges resulting from the Partnership's July 1, 2013 impairment testing, and no event indicating impairment has occurred subsequent to that date.

(2) Acquisition

On July 2, 2012, the Partnership, through a wholly-owned subsidiary, acquired all of the issued and outstanding common stock of Clearfield Energy, Inc. and its wholly owned subsidiaries (collectively, “Clearfield”). Clearfield’s business included crude oil pipelines, a barge loading terminal on the Ohio River, a rail loading terminal on the Ohio Central Railroad network, a trucking fleet and brine disposal wells. All of these assets are included in the Partnership’s ORV segment.

Purchase Price Allocation

The Partnership paid approximately $215.4 million in cash in the acquisition. The following table is a summary of the consideration paid in the Clearfield acquisition and the purchase price allocation for the fair value of the assets acquired and liabilities assumed at the acquisition date:

Purchase Price Allocation (in thousands):		
Purchase Price to Clearfield Energy, Inc.	$	215,397
Total Purchase Price	$	215,397
Assets acquired:		
Current assets		17,622
Assets held for disposition		19,358
Property, plant and equipment		91,422
Goodwill		153,802
Intangibles		37,600
Liabilities assumed:		
Current liabilities		(28,274)
Liabilities held for disposition		(1,400)
Deferred taxes		(65,228)
Long term liabilities		(9,505)
Total purchase price	$	215,397

From the period July 2, 2012 to September 30, 2012, the Partnership recognized $52.9 million of crude oil buy/sell, crude oil transportation and brine service sales related to properties acquired in the Clearfield acquisition. For the period July 2, 2012 to September 30, 2012, the Partnership recognized $46.1 million of net operating expense related to properties acquired in the Clearfield acquisition.

Pro Forma Information

The following unaudited pro forma condensed financial data for the nine months ended September 30, 2012 gives effect to the Clearfield acquisition as if it had occurred on January 1, 2012. The unaudited pro forma condensed financial information has been included for comparative purposes only and is not necessarily indicative of the results that might have occurred had the transactions taken place on the dates indicated and is not intended to be a projection of future results.

	Nine Months Ended September 30, 2012
Pro forma total revenues	$ 1,371,219
Pro forma net loss	$ (18,005)
Pro forma net loss attributable to Crosstex Energy, L.P.	$ (17,892)
Pro forma net loss per common unit:	
Basic and Diluted	$ (0.32)

(3) Long-Term Debt

As of September 30, 2013 and December 31, 2012, long-term debt consisted of the following (in thousands):

	September 30, 2013	December 31, 2012
Bank credit facility (due 2016), interest based on Prime and/or LIBOR plus an applicable margin, interest rate at September 30, 2013 and December 31, 2012 was 3.6% and 4.3%, respectively	$ 76,000	$ 71,000
Senior unsecured notes (due 2018), net of discount of $8.3 million and $9.7 million, respectively, which bear interest at the rate of 8.875%	716,728	715,305
Senior unsecured notes (due 2022), which bear interest at the rate of 7.125%	250,000	250,000
Debt classified as long-term	$ 1,042,728	$ 1,036,305

Credit Facility. As of September 30, 2013, there was $62.3 million in outstanding letters of credit and $76.0 million in outstanding borrowings under the Partnership's bank credit facility, leaving approximately $496.7 million available for future borrowing based on the borrowing capacity of $635.0 million. As of September 30, 2013, based on our maximum permitted consolidated leverage ratio (as defined in the amended credit facility), we could borrow approximately $271.4 million of additional funds.

In January 2013, the Partnership amended the credit facility to, among other things, (i) decrease the minimum consolidated interest coverage ratio (as defined in the amended credit facility, being generally computed as the ratio of consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges to consolidated interest charges) to 2.25 to 1.0 for the fiscal quarters ending September 30, 2013 and December 31, 2013, with a minimum ratio of 2.50 to 1.0 for each fiscal quarter ending thereafter, (ii) increase the maximum permitted consolidated leverage ratio (as defined in the amended credit facility, being generally computed as the ratio of total funded debt to consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges) to 5.50 to 1.0 for each fiscal quarter ending on or prior to December 31, 2013, with a maximum ratio of 5.25 to 1.0 for each fiscal quarter ending thereafter, and (iii) eliminate the existing and any future step-up in the maximum permitted consolidated leverage ratio for acquisitions.

In August 2013, the Partnership amended the credit facility to, among other things, (i) allow the Partnership to make additional investments in joint ventures and subsidiaries that are not guarantors of the Partnership's obligations under the amended credit facility, (ii) decrease the minimum consolidated interest coverage ratio (as defined in the amended credit facility, being generally computed as the ratio of consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges to consolidated interest charges) to 2.25 to 1.0 for the fiscal quarters ending March 31, 2014, June 30, 2014, September 30, 2014 and December 31, 2014, with a minimum ratio of 2.50 to 1.0 for each fiscal quarter ending thereafter and (iii) increase the maximum permitted consolidated leverage ratio (as defined in the amended credit facility, being generally computed as the ratio of total funded debt to consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges) to 5.50 to 1.0 for the fiscal quarters ending March 31, 2014, June 30, 2014 and September 30, 2014, with a maximum ratio of 5.25 to 1.0 for each fiscal quarter ending thereafter.

The credit facility is guaranteed by substantially all of our subsidiaries and is secured by first priority liens on substantially all of our assets and those of the guarantors, including all material pipeline, gas gathering and processing assets, all material working capital assets and a pledge of all of our equity interests in substantially all of our subsidiaries. We may prepay all loans under the credit facility at any time without premium or penalty (other than customary LIBOR breakage costs), subject to certain notice requirements. The credit facility requires mandatory prepayments of amounts outstanding thereunder with the net proceeds of certain asset sales, extraordinary receipts, equity issuances and debt incurrences, but these mandatory prepayments do not require any reduction of the lenders' commitments under the credit facility.

All other material terms of the credit facility are described in Part II, "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Indebtedness" in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2012. The Partnership expects to be in compliance with all credit facility covenants for at least the next twelve months.

Non-Guarantors. All senior unsecured notes are jointly and severally guaranteed by each of the Partnership's current material subsidiaries (the "Guarantors"), with the exception of its regulated Louisiana subsidiaries (which may only guarantee up to $500.0 million of the Partnership's debt) and Crosstex Energy Finance Corporation (a wholly owned Delaware corporation that was organized for the sole purpose of being a co-issuer of certain of the Partnership's indebtedness, including the senior unsecured notes). Guarantors may not sell or otherwise dispose of all or substantially all of their properties or assets, or consolidate with or merge into another company if such a sale would cause a default under the terms of the senior unsecured notes. There are no significant restrictions on the ability of the Partnership or any Guarantor to obtain funds from its subsidiaries by dividend or loan. Since certain wholly owned subsidiaries do not guarantee the senior unsecured notes, the condensed consolidating financial statements of the Guarantors and non-guarantors for the three and nine months ended September 30, 2013 and 2012 are disclosed below in accordance with Rule 3-10 of Regulation S-X. Comprehensive income (loss) is not included in the condensed consolidating statements of operations of the Guarantors and non-guarantors for the three and nine months ended September 30, 2013 and 2012 as these amounts are not considered material.

CROSSTEX ENERGY, L.P.

Notes to Condensed Consolidated Financial Statements-(Continued)

Condensed Consolidating Balance Sheets
September 30, 2013

	Guarantors	Non-Guarantors	Elimination	Consolidated
		(In thousands)		
ASSETS				
Total current assets	$ 216,038	$ 11,074	$ —	$ 227,112
Property, plant and equipment, net	1,579,845	211,774	—	1,791,619
Total other assets	597,623	—	—	597,623
Total assets	$ 2,393,506	$ 222,848	$ —	$ 2,616,354
LIABILITIES & PARTNERS’ CAPITAL				
Total current liabilities	$ 247,714	$ 7,423	$ —	$ 255,137
Long-term debt	1,042,728	—	—	1,042,728
Other long-term liabilities	93,815	—	—	93,815
Partners’ capital	1,009,249	215,425	—	1,224,674
Total liabilities & partners’ capital	$ 2,393,506	$ 222,848	$ —	$ 2,616,354

December 31, 2012

	Guarantors	Non-Guarantors	Elimination	Consolidated
		(In thousands)		
ASSETS				
Total current assets	$ 246,165	$ 11,055	$ —	$ 257,220
Property, plant and equipment, net	1,276,097	195,151	—	1,471,248
Total other assets	694,121	—	—	694,121
Total assets	$ 2,216,383	$ 206,206	$ —	$ 2,422,589
LIABILITIES & PARTNERS’ CAPITAL				
Total current liabilities	$ 273,151	$ 2,392	$ —	$ 275,543
Long-term debt	1,036,305	—	—	1,036,305
Other long-term liabilities	101,660	—	—	101,660
Partners’ capital	805,267	203,814	—	1,009,081
Total liabilities & partners’ capital	$ 2,216,383	$ 206,206	$ —	$ 2,422,589

CROSSTEX ENERGY, L.P.

Notes to Condensed Consolidated Financial Statements-(Continued)

Condensed Consolidating Statements of Operations
For the Three Months Ended September 30, 2013

	Guarantors	Non-Guarantors	Elimination	Consolidated
		(In thousands)		
Total revenues	$ 456,177	$ 17,955	$ (5,770)	$ 468,362
Total operating costs and expenses	(527,346)	(8,613)	5,770	(530,189)
Operating income (loss)	(71,169)	9,342	—	(61,827)
Interest expense, net	(16,430)	—	—	(16,430)
Other expense	(27)	—	—	(27)
Income (loss) before non-controlling interest and income taxes	(87,626)	9,342	—	(78,284)
Income tax provision	(554)	—	—	(554)
Net income (loss) attributable to Crosstex Energy, L.P.	$ (88,180)	$ 9,342	$ —	$ (78,838)

For the Three Months Ended September 30, 2012

	Guarantors	Non-Guarantors	Elimination	Consolidated (As Adjusted)
		(In thousands)		
Total revenues	$ 430,064	$ 20,468	$ (5,585)	$ 444,947
Total operating costs and expenses	(438,876)	(9,859)	5,585	(443,150)
Operating income (loss)	(8,812)	10,609	—	1,797
Interest expense, net	(23,220)	(9)	—	(23,229)
Other income	5,950	—	—	5,950
Income (loss) before non-controlling interest and income taxes	(26,082)	10,600	—	(15,482)
Income tax provision	(665)	(7)	—	(672)
Net loss attributable to non-controlling interest	—	54	—	54
Net income (loss) attributable to Crosstex Energy, L.P.	$ (26,747)	$ 10,647	$ —	$ (16,100)

For the Nine Months Ended September 30, 2013

	Guarantors	Non-Guarantors	Elimination	Consolidated
		(In thousands)		
Total revenues	$ 1,331,143	$ 56,461	$ (18,964)	$ 1,368,640
Total operating costs and expenses	(1,401,180)	(25,134)	18,964	(1,407,350)
Operating income (loss)	(70,037)	31,327	—	(38,710)
Interest expense, net	(54,874)	—	—	(54,874)
Other income	262	—	—	262
Income (loss) before non-controlling interest and income taxes	(124,649)	31,327	—	(93,322)
Income tax provision	(2,097)	—	—	(2,097)
Net income (loss) attributable to Crosstex Energy, L.P.	$ (126,746)	$ 31,327	$ —	$ (95,419)

CROSSTEX ENERGY, L.P.

Notes to Condensed Consolidated Financial Statements-(Continued)

For the Nine Months Ended September 30, 2012

	Guarantors	Non-Guarantors	Elimination	Consolidated (As Adjusted)
		(In thousands)		
Total revenues	$ 1,221,502	$ 64,946	$ (21,140)	$ 1,265,308
Total operating costs and expenses	(1,213,993)	(28,715)	21,140	(1,221,568)
Operating income	7,509	36,231	—	43,740
Interest expense, net	(63,867)	(65)	—	(63,932)
Other income	5,975	—	—	5,975
Income (loss) before non-controlling interest and income taxes	(50,383)	36,166	—	(14,217)
Income tax provision	(1,493)	(14)	—	(1,507)
Net loss attributable to non-controlling interest	—	163	—	163
Net income (loss) attributable to Crosstex Energy, L.P.	$ (51,876)	$ 36,315	$ —	$ (15,561)

Condensed Consolidating Statements of Cash Flows
For the Nine Months Ended September 30, 2013

	Guarantors	Non-Guarantors	Elimination	Consolidated
		(In thousands)		
Net cash flows provided by operating activities	$ 46,028	$ 42,603	$ —	$ 88,631
Net cash flows used in investing activities	$ (368,318)	$ (22,887)	$ —	$ (391,205)
Net cash flows provided by (used in) financing activities	$ 302,459	$ (19,716)	$ 19,716	$ 302,459

For the Nine Months Ended September 30, 2012

	Guarantors	Non-Guarantors	Elimination	Consolidated
		(In thousands)		
Net cash flows provided by (used in) operating activities	$ (3,335)	$ 47,916	$ —	$ 44,581
Net cash flows used in investing activities	$ (393,866)	$ (547)	$ —	$ (394,413)
Net cash flows provided by (used in) financing activities	$ 328,207	$ (46,989)	$ 46,989	$ 328,207

(4) Other Long-term Liabilities

The Partnership has the following assets under capital leases as of September 30, 2013 (in thousands):

Compressor equipment	$ 37,199
Less: Accumulated amortization	(16,401)
Net assets under capital leases	$ 20,798

The following are the minimum lease payments to be made in each of the following years indicated for the capital leases in effect as of September 30, 2013 (in thousands):

Fiscal Year		
2013	$	1,146
2014		4,582
2015		4,582
2016		4,582
2017		6,910
Thereafter		5,189
Less: Interest		(4,169)
Net minimum lease payments under capital lease		22,822
Less: Current portion of net minimum lease payments		(4,449)
Long-term portion of net minimum lease payments	$	18,373

(5) Partners' Capital

(a) Issuance of Common Units

In June 2013, the Partnership issued 8,280,000 common units representing limited partner interests in the Partnership (including 1,080,000 common units issued pursuant to the exercise of the underwriters' option to purchase additional common units) at a public offering price of $20.33 per common unit for net proceeds of $162.0 million. The net proceeds from the common unit offering were used for capital expenditures for currently identified projects, including the Cajun-Sibon NGL pipeline expansion, and for general partnership purposes. Pending such use, the Partnership repaid outstanding borrowings under its credit facility. The General Partner did not exercise its option to make a general partner contribution to maintain its then current general partner percentage interest in connection with this offering.

In January 2013, the Partnership issued 8,625,000 common units representing limited partner interests in the Partnership at a public offering price of $15.15 per common unit for net proceeds of $125.4 million. Concurrent with the public offering, the Partnership issued 2,700,000 common units representing limited partner interests in the Partnership at an offering price of $14.55 per unit for net proceeds of $39.2 million. The net proceeds from both common unit offerings were used for capital expenditures, to repay bank borrowings and for general partnership purposes. The General Partner did not exercise its option to make a general partner contribution to maintain its then current general partner percentage interest in connection with these offerings.

In May 2013, the Partnership entered into an Equity Distribution Agreement (the "EDA") with BMO Capital Markets Corp. ("BMOCM"). This EDA replaced the previous equity distribution agreement entered into in March 2013 between BMOCM and the Partnership. Pursuant to the terms of the EDA, the Partnership may from time to time through BMOCM, as its sales agent, sell common units representing limited partner interests having an aggregate offering price of up to $75.0 million. Sales of such common units will be made by means of ordinary brokers' transactions through the facilities of the Nasdaq Global Select Market LLC at market prices, in block transactions or as otherwise agreed by BMOCM and the Partnership. Under the terms of the EDA, the Partnership may sell common units from time to time to BMOCM as principal for its own account at a price to be agreed upon at the time of sale. For any such sales, the Partnership will enter into a separate terms agreement with BMOCM.

Through September 30, 2013, the Partnership sold an aggregate of 3,370,486 common units under the EDA and prior equity distribution agreement with BMOCM, generating proceeds of approximately $62.9 million (net of approximately $0.9 million of commissions to BMOCM). The Partnership used the net proceeds for general partnership purposes, including working capital, capital expenditures and repayments of indebtedness.

(b) Distributions

Unless restricted by the terms of the Partnership's credit facility and/or the indentures governing the Partnership's 8.875% senior notes due 2018 (the "2018 Notes") or the Partnership's 7.125% senior notes due 2022 (the "2022 Notes" and, together with the 2018 Notes, "all senior unsecured notes"), the Partnership must make distributions of 100% of available cash, as defined in the partnership agreement, within45 days following the end of each quarter. A summary of the distribution activity relating to the common units and the preferred units (which are paid-in-kind "PIK") for the nine months ended September 30, 2013 is provided below:

Declaration period	Distribution/unit		PIK Units Distributed (1)	Date paid/payable
Q4 2012	$	0.33	375,382	February 14, 2013
Q1 2013	$	0.33	384,731	May 13, 2013
Q2 2013	$	0.33	394,313	August 12, 2013
Q3 2013	$	0.34	—	November 12, 2013

(1) Represents distributions on preferred units paid-in-kind through the issuance of additional preferred units.

(c) Earnings per Unit and Dilution Computations

The Partnership had common units and preferred units outstanding during thethree and nine months ended September 30, 2013 and 2012.

The preferred units are entitled to a quarterly distribution PIK in the form of additional preferred units equal to the greater of$0.2125 per unit or the amount of the quarterly distribution per unit paid to common unitholders, subject to certain adjustments. Income is allocated to the preferred units in an amount equal to the quarterly distribution with respect to the period earned. The fair value of the PIK preferred unit distributions is based on the market value of common units on the record date of such distributions.

As required under FASB Accounting Standards Codification ("ASC") 260-10-45-61A, unvested share-based payments that entitle employees to receive non-forfeitable distributions are considered participating securities, as defined in FASB ASC 260-10-20, for earnings per unit calculations. The following table reflects the computation of basic earnings per limited partner unit for the periods presented (in thousands except per unit amounts):

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2013		2012		2013		2012	
Limited partners’ interest in net loss	$	(85,673)	$	(21,431)	$	(115,909)	$	(30,487)
Distributed earnings allocated to:								
Common units (1)(2)	$	30,308	$	20,948	$	82,623	$	55,752
Unvested restricted units (1)(2)		399		310		1,195		1,008
Total distributed earnings	$	30,707	$	21,258	$	83,818	$	56,760
Undistributed loss allocated to:								
Common units	$	(114,848)	$	(41,977)	$	(196,879)	$	(85,676)
Unvested restricted units		(1,532)		(712)		(2,848)		(1,571)
Total undistributed loss	$	(116,380)	$	(42,689)	$	(199,727)	$	(87,247)
Net loss allocated to:								
Common units	$	(84,540)	$	(21,029)	$	(114,256)	$	(29,924)
Unvested restricted units		(1,133)		(402)		(1,653)		(563)
Total limited partners’ interest in net loss	$	(85,673)	$	(21,431)	$	(115,909)	$	(30,487)
Basic and diluted net loss per unit:								
Basic and diluted common unit	$	(0.95)	$	(0.34)	$	(1.38)	$	(0.53)

(1) Three months ended September 30, 2013 represents a declared distribution of $0.34 per unit payable on November 12, 2013 and nine months ended September 30, 2013 represents distributions paid of $0.66 per unit and distributions declared of $0.34 per unit payable November 12, 2013.

(2) Three months ended September 30, 2012 represents a declared distribution of $0.33 per unit paid on November 14, 2012. Nine months ended September 30, 2012 represents distributions paid of $0.66 per unit and distributions declared of $0.33 per unit paid November 14, 2012.

The following are the unit amounts used to compute the basic and diluted earnings per limited partner unit for the three and nine months ended September 30, 2013 and 2012 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Basic and diluted weighted average units outstanding:				
Weighted average limited partner common units outstanding	89,229	62,027	82,623	56,315

All common unit equivalents were antidilutive in the three and nine months ended September 30, 2013 and 2012 because the limited partners were allocated net losses in these periods.

The General Partner is entitled to a distribution in relation to its percentage interest with respect to all distributions made to common unitholders. If the distributions are in excess of $0.2125 per unit, distributions are made to the General Partner in accordance with its current percentage interest with the remainder to the common and preferred unitholders, subject to the payment of incentive distributions as described below to the extent that certain target levels of cash distributions are achieved.

When quarterly distributions are made pro-rata to common and preferred unitholders, net income for the General Partner consists of incentive distributions to the extent earned, a deduction for stock-based compensation attributable to CEI's stock options and restricted shares and the percentage interest of the original Partnership's net income (loss) adjusted for the CEI stock-based compensation specifically allocated to the General Partner. When quarterly distributions are made solely to the preferred unitholders, the net income for the General Partner consists of the CEI stock-based compensation deduction and the General Partner's percentage interest of the Partnership's net income (loss) after the allocation of income to the preferred unitholders with respect to their preferred distribution adjusted for the CEI stock-based compensation specifically allocated to the General Partner.

Under the quarterly incentive distribution provisions, generally the General Partner is entitled to 13.0% of amounts the Partnership distributes in excess of $0.25 per unit, 23.0% of the amounts the Partnership distributes in excess of $0.3125 per unit and 48.0% of amounts the Partnership distributes in excess of $0.375 per unit. The net income (loss) allocated to the General Partner is as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Income allocation for incentive distributions	$ 1,296	$ 1,157	$ 4,170	$ 3,266
Stock-based compensation attributable to CEI's restricted shares	(1,480)	(1,166)	(5,457)	(3,443)
General Partner interest in net income (loss)	(1,267)	(300)	(1,720)	(243)
General Partner share of net loss	$ (1,451)	$ (309)	$ (3,007)	$ (420)

(6) Employee Incentive Plans

(a) Long-Term Incentive Plans

The Partnership accounts for share-based compensation in accordance with FASB ASC 718, which requires that compensation related to all stock-based awards, including stock options, be recognized in the consolidated financial statements. On May 9, 2013, the Partnership's unitholders approved the amended and restated Crosstex Energy GP, LLC Long-Term Incentive Plan (the "Plan"). Amendments to the Plan include an increase in the number of common units representing limited partner interests in the Partnership authorized for issuance under the Plan by 3,470,000 common units to an aggregate of

9,070,000 common units. In addition, the Plan includes technical amendments to certain other provisions of the Plan (i) to describe awards of restricted units as restricted incentive units, (ii) to revise the change in control definition to (among other things) eliminate and clarify certain change in control events, (iii) to make minor changes to better conform certain provisions to applicable law and (iv) to include minor updates to clarify the meaning of, and consistently describe, certain terms thereunder.

The Partnership and CEI each have similar unit or share-based payment plans for employees, which are described below. Share-based compensation associated with the CEI share-based compensation plan awarded to officers and employees of the Partnership are recorded by the Partnership since CEI has no substantial or managed operating activities other than its interest in the Partnership. Amounts recognized in the condensed consolidated financial statements with respect to these plans are as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Cost of share-based compensation charged to general and administrative expense	$ 2,599	$ 2,193	$ 9,675	$ 6,546
Cost of share-based compensation charged to operating expense	423	310	1,403	950
Total amount charged to income	$ 3,022	$ 2,503	$ 11,078	$ 7,496

(b) Restricted Incentive Units

The restricted incentive units are valued at their fair value at the date of grant which is equal to the market value of common units on such date. A summary of the restricted incentive unit activity for the nine months ended September 30, 2013 is provided below:

	Nine Months Ended September 30, 2013	
Crosstex Energy, L.P. Restricted Incentive Units:	**Number of Units**	**Weighted Average Grant-Date Fair Value**
Non-vested, beginning of period	1,003,159	$ 13.31
Granted	625,339	16.19
Vested*	(396,927)	9.50
Forfeited	(52,648)	13.52
Non-vested, end of period	1,178,923	$ 16.11
Aggregate intrinsic value, end of period (in thousands)	$ 23,461	

* Vested units include 113,804 units withheld for payroll taxes paid on behalf of employees.

The Partnership issued restricted incentive units in 2013 to officers and other employees. These restricted incentive units typically vest at the end of three years and are included in the restricted incentive units outstanding and the current share-based compensation cost calculations at September 30, 2013. In March 2013, the Partnership issued 57,897 restricted incentive units with a fair value of $1.0 million to officers and certain employees as bonus payments for 2012, which vested immediately and are included in the restricted incentive units granted and vested line items above.

A summary of the restricted incentive units' aggregate intrinsic value (market value at vesting date) and fair value of units vested during the three and nine months ended September 30, 2013 and 2012 are provided below (in thousands):

Crosstex Energy, L.P. Restricted Incentive Units:	Three Months Ended September 30, 2013	2012	Nine Months Ended September 30, 2013	2012
Aggregate intrinsic value of units vested	$ 2,457	$ 448	$ 6,750	$ 4,031
Fair value of units vested	$ 1,275	$ 452	$ 3,771	$ 2,060

As of September 30, 2013, there was $9.0 million of unrecognized compensation cost related to non-vested restricted incentive units. That cost is expected to be recognized over a weighted-average period of 1.5 years.

(c) Unit Options

A summary of the unit option activity for thenine months ended September 30, 2013 is provided below:

Crosstex Energy, L.P. Unit Options:	Nine Months Ended September 30, 2013 Number of Units	Weighted Average Exercise Price
Outstanding, beginning of period	349,018	$ 7.25
Exercised	(132,986)	5.56
Forfeited	(3,109)	23.60
Outstanding, end of period	212,923	$ 8.07
Options exercisable at end of period	212,923	
Weighted average contractual term (years) end of period:		
Options outstanding	5.5	
Options exercisable	5.5	
Aggregate intrinsic value end of period (in thousands):		
Options outstanding	$ 2,803	
Options exercisable	$ 2,803	

A summary of the unit options intrinsic value exercised (market value in excess of exercise price at date of exercise) and fair value of units exercised (value per Black-Scholes-Merton option pricing model at date of grant) during the three and nine months ended September 30, 2013 and 2012 are provided below (in thousands):

Crosstex Energy, L.P. Unit Options:	Three Months Ended September 30, 2013	2012	Nine Months Ended September 30, 2013	2012
Intrinsic value of unit options exercised	$ 356	$ 327	$ 1,716	$ 805
Fair value of unit options vested	$ —	$ —	$ 254	$ 277

As of September 30, 2013, all options were vested and fully expensed.

(d) Crosstex Energy, Inc.'s Restricted Stock

On May 9, 2013, CEI's stockholders approved the amended and restated Crosstex Energy, Inc. 2009 Long-Term Incentive Plan (the "CEI Plan"). Amendments to the CEI Plan included an increase in the number of shares of CEI's common stock authorized for issuance under the CEI Plan by 1,785,000 shares to an aggregate of 4,385,000 shares of common stock. In addition, the CEI Plan amendments included technical amendments to certain other provisions of the CEI Plan (i) to clarify that awards of restricted stock units may be granted as stock awards, (ii) to revise the change of control definition to (among other things) eliminate and clarify certain change of control events, (iii) to make minor changes to better conform certain provisions to applicable law and (iv) to include minor updates to clarify the meaning of, and consistently describe, certain terms thereunder.

CEI's restricted shares are valued at their fair value at the date of grant which is equal to the market value of the common stock on such date. A summary of the restricted share activities for the nine months ended September 30, 2013 is provided below:

	Nine Months Ended September 30, 2013	
Crosstex Energy, Inc. Restricted Shares:	**Number of Shares**	**Weighted Average Grant-Date Fair Value**
Non-vested, beginning of period	1,329,162	$ 9.75
Granted	632,912	15.08
Vested*	(445,177)	7.43
Forfeited	(63,864)	11.69
Non-vested, end of period	1,453,033	$ 12.69
Aggregate intrinsic value, end of period (in thousands)	$ 30,354	

* Vested shares include 124,493 shares withheld for payroll taxes paid on behalf of employees.

CEI issued restricted shares in 2013 to officers and other employees. These restricted shares typically vest at the end of three years and are included in restricted shares outstanding and the current share-based compensation cost calculations at September 30, 2013. In March 2013, CEI issued 60,018 restricted shares with a fair value of $1.0 million to officers and certain employees as bonus payments for 2012, which vested immediately and are included in restricted shares granted and vested in the above line items.

A summary of the restricted shares' aggregate intrinsic value (market value at vesting date) and fair value of shares vested during the three and nine months ended September 30, 2013 and 2012 are provided below (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
Crosstex Energy, Inc. Restricted Shares:	**2013**	**2012**	**2013**	**2012**
Aggregate intrinsic value of shares vested	$ 3,290	$ 537	$ 7,593	$ 3,963
Fair value of shares vested	$ 1,123	$ 448	$ 3,307	$ 1,714

As of September 30, 2013, there was $9.0 million of unrecognized compensation costs related to non-vested CEI restricted shares. The cost is expected to be recognized over a weighted average period of 1.4 years.

(e) Crosstex Energy, Inc.'s Stock Options

CEI stock options have not been granted to officers or employees of the Partnership since 2005. There are 37,500 CEI stock options vested and exercisable at September 30, 2013.

(7) **Derivatives**

Commodity Swaps

The Partnership manages its exposure to fluctuations in commodity prices by hedging the impact of market fluctuations. Swaps are used to manage and hedge price and location risks related to these market exposures. Swaps are also used to manage margins on offsetting fixed-price purchase or sale commitments for physical quantities of natural gas and NGLs.

CROSSTEX ENERGY, L.P.

Notes to Condensed Consolidated Financial Statements-(Continued)

The Partnership commonly enters into various derivative financial transactions which it does not designate as accounting hedges. These transactions include "swing swaps," "storage swaps," "basis swaps," "processing margin swaps," "liquids swaps" and "put options." Swing swaps are generally short-term in nature (one month) and are usually entered into to protect against changes in the volume of daily versus first-of-month index priced gas supplies or markets. Storage swap transactions protect against changes in the value of products that the Partnership has stored to serve various operational requirements (gas) or has in inventory due to short term constraints in moving the product to market (liquids/condensate). Basis swaps are used to hedge basis location price risk due to buying gas into one of the Partnership's systems on one index and selling gas off that same system on a different index. Processing margin financial swaps are used to hedge fractionation spread risk at the Partnership's processing plants relating to the option to process versus bypassing the Partnership's equity gas. Liquids financial swaps are used to hedge price risk on percent of liquids contracts. Put options are purchased to hedge against declines in pricing and as such, represent options, not obligations, to sell the related underlying volumes at a fixed price.

Changes in the fair value of the Partnership's mark to market derivatives are recognized in earnings in the period of change. The effective portion of changes in the fair value of cash flow hedges is recorded in AOCI until the related anticipated future cash flow is recognized in earnings. The ineffective portion is recorded in earnings immediately.

The components of (gain) loss on derivatives in the condensed consolidated statements of operations relating to commodity swaps are provided below (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Change in fair value of derivatives that are not designated as hedging instruments	$ 1,012	$ 433	$ 768	$ (5,481)
Realized losses on derivatives	591	308	906	3,547
Ineffective portion of derivatives designated as hedging instruments	31	18	(12)	(43)
(Gains) losses on derivatives	$ 1,634	$ 759	$ 1,662	$ (1,977)

The fair value of derivative assets and liabilities relating to commodity swaps are as follows (in thousands):

	September 30, 2013	December 31, 2012
Fair value of derivative assets — current, designated	$ 287	$ 724
Fair value of derivative assets — current, non-designated	823	2,510
Fair value of derivative liabilities — current, designated	(313)	(105)
Fair value of derivative liabilities — current, non-designated	(287)	(1,205)
Fair value of derivative liabilities — long term, designated	(19)	—
Net fair value of derivatives	$ 491	$ 1,924

Set forth below are the summarized notional volumes and fair value of all instruments held for price risk management purposes and related physical offsets as of September 30, 2013 (all gas volumes are expressed in million British thermal units ("MMBtus") and liquids volumes are expressed in gallons). The remaining terms of the contracts extend no later than December 2014.

	September 30, 2013	
Transaction Type	**Volume**	**Fair Value**
	(In thousands)	
Cash Flow Hedges:		
Liquids swaps (short contracts)	(9,322)	$ (45)
Total swaps designated as cash flow hedges		$ (45)
*Mark to Market Derivatives:**		
Swing swaps (long contracts)	1,659	$ 4
Physical offsets to swing swap transactions (short contracts)	(1,659)	(1)
Processing margin hedges — liquids (short contracts)	(3,926)	256
Processing margin hedges — gas (long contracts)	422	(125)
Liquids swaps - non-designated (short contracts)	(1,369)	308
Storage swap transactions — (short contracts)	(100)	21
Storage swap transactions — liquids inventory (long contracts)	420	3
Storage swap transactions — liquids inventory (short contracts)	(1,680)	70
Total mark to market derivatives		$ 536

* All are gas contracts except as otherwise noted.

On all transactions where the Partnership is exposed to counterparty risk, the Partnership analyzes the counterparty's financial condition prior to entering into an agreement, establishes limits and monitors the appropriateness of these limits on an ongoing basis. The Partnership primarily deals with two types of counterparties, financial institutions and other energy companies, when entering into financial derivatives on commodities. The Partnership has entered into Master International Swaps and Derivatives Association Agreements ("ISDAs") with its counterparties. If the Partnership's counterparties failed to perform under existing swap contracts entered into under these ISDAs, the Partnership's maximum loss as of September 30, 2013 of $0.9 million would be reduced to $0.7 million due to the offsetting of gross fair value payables against gross fair value receivables as allowed by the ISDAs.

Impact of Cash Flow Hedges

The impact of realized gains or losses from derivatives designated as cash flow hedge contracts in the condensed consolidated statements of operations is summarized below (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
Increase in Midstream Revenue	**2013**	**2012**	**2013**	**2012**
Liquids realized gain included in Midstream revenue	$ 159	$ 456	$ 819	$ 851

Natural Gas

As of September 30, 2013, the Partnership had no balances in AOCI related to natural gas.

Liquids

As of September 30, 2013, an unrealized derivative fair value net loss of less than $0.1 million related to cash flow hedges of liquids price risk was recorded in AOCI. Of that amount, a net loss of less than $0.1 million is expected to be reclassified into earnings through September 2014. The actual reclassification to earnings will be based on mark to market prices at the contract settlement date, along with the realization of the gain or loss on the related physical volume, which is not reflected in the above table.

Derivatives Other Than Cash Flow Hedges

Assets and liabilities related to third party derivative contracts, swing swaps, basis swaps, storage swaps, processing margin swaps and liquids swaps are included in the fair value of derivative assets and liabilities and the profit and loss on the mark to market value of these contracts are recorded net as (gain) loss on derivatives in the condensed consolidated statement of operations. The Partnership estimates the fair value of all of its energy trading contracts using Level 1 and Level 2 inputs for future commodity prices that are readily available in public markets or can be derived from information available in publicly quoted markets. The estimated fair value of energy trading contracts by maturity date was as follows (in thousands):

	Maturity Periods			
	Less than one year	One to two years	More than two years	Total fair value
September 30, 2013	$ 536	$ —	$ —	$ 536

(8) Fair Value Measurements

FASB ASC 820 sets forth a framework for measuring fair value and required disclosures about fair value measurements of assets and liabilities. Fair value under FASB ASC 820 is defined as the price at which an asset could be exchanged in a current transaction between knowledgeable, willing parties. A liability’s fair value is defined as the amount that would be paid to transfer the liability to a new obligor, not the amount that would be paid to settle the liability with the creditor. Where available, fair value is based on observable market prices or parameters or derived from such prices or parameters. Where observable prices or inputs are not available, use of unobservable prices or inputs are used to estimate the current fair value, often using an internal valuation model. These valuation techniques involve some level of management estimation and judgment, the degree of which is dependent on the item being valued.

FASB ASC 820 established a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value. These tiers include: Level 1, defined as observable inputs such as quoted prices in active markets; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions.

The Partnership’s derivative contracts primarily consist of commodity swap contracts which are not traded on a public exchange. The fair values of commodity swap contracts are determined using discounted cash flow techniques. The techniques incorporate Level 1 and Level 2 inputs for future commodity prices that are readily available in public markets or can be derived from information available in publicly quoted markets. These market inputs are utilized in the discounted cash flow calculation considering the instrument’s term, notional amount, discount rate and credit risk and are classified as Level 2 in hierarchy.

Net assets measured at fair value on a recurring basis are summarized below (in thousands):

	September 30, 2013 Level 2	December 31, 2012 Level 2
Commodity Swaps*	$ 491	$ 1,924
Total	$ 491	$ 1,924

* Unrealized gains or losses on commodity derivatives qualifying for hedge accounting are recorded in AOCI at each measurement date. The fair value of derivative contracts included in assets or liabilities for risk management activities represents the amount at which the instruments could be exchanged in a current arms-length transaction adjusted for credit risk of the Partnership and/or the counterparty as required under FASB ASC 820.

Fair Value of Financial Instruments

The estimated fair value of the Partnership's financial instruments has been determined by the Partnership using available market information and valuation methodologies. Considerable judgment is required to develop the estimates of fair value; thus, the estimates provided below are not necessarily indicative of the amount the Partnership could realize upon the sale or refinancing of such financial instruments (in thousands):

	September 30, 2013		December 31, 2012	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 1,042,728	$ 1,102,563	$ 1,036,305	$ 1,118,875
Obligations under capital lease	$ 22,822	$ 24,381	$ 25,257	$ 27,667

The carrying amounts of the Partnership's cash and cash equivalents, accounts receivable and accounts payable approximate fair value due to the short-term maturities of these assets and liabilities.

The Partnership had $76.0 million in borrowings under its revolving credit facility included in long-term debt as ofSeptember 30, 2013 and $71.0 million at December 31, 2012. As borrowings under the credit facility accrue interest under floating interest rate structures, the carrying value of such indebtedness approximates fair value for the amounts outstanding under the credit facility. As of September 30, 2013 and December 31, 2012, the Partnership also had borrowings totaling $716.7 million and $715.3 million, net of discount, respectively, under the 2018 Notes with a fixed rate of8.875% and borrowings of $250.0 million under the 2022 Notes with a fixed rate of7.125%. The fair value of all senior unsecured notes as of September 30, 2013 and December 31, 2012 was based on Level 1 inputs from third-party market quotations. The fair value of obligations under capital leases was calculated using Level 2 inputs from third-party banks.

(9) Commitments and Contingencies

(a) Employment and Severance Agreements

Certain members of management of the Partnership are parties to employment and/or severance agreements with the General Partner. The employment and severance agreements provide those managers with severance payments in certain circumstances and, in the case of employment agreements, prohibit each such person from competing with the General Partner or its affiliates for a certain period of time following the termination of such person's employment.

(b) Environmental Issues

The Partnership acquired LIG Pipeline Company and its subsidiaries on April 1, 2004. Contamination from historical operations was identified during due diligence at a number of sites owned by the acquired companies. The seller, AEP, has indemnified the Partnership for these identified sites. Moreover, AEP has entered into an agreement with a third party company pursuant to which the remediation costs associated with these sites have been assumed by this third party company that specializes in remediation work. To date, 23 of the 25 sites requiring remediation have been completed and have received a "No

Further Action" status from the Louisiana Department of Environmental Quality. The remainingtwo sites continuing with remediation efforts are expected to reach closure in 2013. The Partnership does not expect to incur any material liability with these sites; however, there can be no assurance that the third parties who have assumed responsibility for remediation of site conditions will fulfill their obligations.

(c) Other

The Partnership is involved in various litigation and administrative proceedings arising in the normal course of business. In the opinion of management, any liabilities that may result from these claims would not individually or in the aggregate have a material adverse effect on its financial position or results of operations.

At times, the Partnership's subsidiaries acquire pipeline easements and other property rights by exercising rights of eminent domain and common carrier. As a result, the Partnership (or its subsidiaries) is a party to a number of lawsuits under which a court will determine the value of pipeline easements or other property interests obtained by the Partnership's subsidiaries by condemnation. Damage awards in these suits should reflect the value of the property interest acquired and the diminution in the value of the remaining property owned by the landowner. However, some landowners have alleged unique damage theories to inflate their damage claims or assert valuation methodologies that could result in damage awards in excess of the amounts anticipated. Although it is not possible to predict the ultimate outcomes of these matters, the Partnership does not expect that awards in these matters will have a material adverse impact on its consolidated results of operations or financial condition.

The Partnership (or its subsidiaries) is defending lawsuits filed by owners of property located near processing facilities or compression facilities constructed by the Partnership as part of its systems. The suits generally allege that the facilities create a private nuisance and have damaged the value of surrounding property. Claims of this nature have arisen as a result of the industrial development of natural gas gathering, processing and treating facilities in urban and occupied rural areas. In January 2012, a plaintiff in one of these lawsuits was awarded a judgment of $2.0 million. The Partnership has appealed the matter and has posted a bond to secure the judgment pending its resolution. The Partnership has accrued a $2.0 million liability related to this matter. Although it is not possible to predict the ultimate outcomes of these matters, the Partnership does not expect that awards in these matters will have a material adverse impact on its consolidated results of operations or financial condition.

In July 2013, the Board of Commissioners for the Southeast Louisiana Flood Protection Authority for New Orleans and surrounding areas filed a lawsuit against approximately 100 energy companies, seeking, among other relief, restoration of wetlands allegedly lost due to historic industry operations in those areas. The suit was filed in Louisiana state court in New Orleans, but was removed to federal court. The amount of damages is unspecified. The Partnership's subsidiary, Crosstex LIG, LLC, is one of the named defendants as the owner of pipelines in the area. The validity of the causes of action, as well as the Partnership's costs and legal exposure, if any, related to the lawsuit are not currently determinable. The Partnership intends to vigorously defend the case.

(10) Segment Information

Identification of operating segments is based principally upon regions served. The Partnership's reportable segments consist of the natural gas gathering, processing and transmission operations located in north Texas and in the Permian Basin in west Texas ("NTX"), the pipelines and processing plants located in Louisiana ("LIG"), the south Louisiana processing and NGL assets ("PNGL") and rail, truck, pipeline, and barge facilities in the ORV. Operating activity for intersegment eliminations is shown in the corporate segment. The Partnership's sales are derived from external domestic customers.

The Partnership evaluates the performance of its operating segments based on operating revenues and segment profits. Corporate expenses include general partnership expenses associated with managing all reportable operating segments. Corporate assets consist primarily of property and equipment, including software, for general corporate support, working capital, debt financing costs and its investment in Howard Energy Partners ("HEP").

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Summarized financial information concerning the Partnership's reportable segments is shown in the following table.

	LIG	NTX	PNGL	ORV	Corporate	Totals
			(In thousands)			
Three Months Ended September 30, 2013						
Sales to external customers	$ 119,716	$ 72,129	$ 181,327	$ 95,190	$ —	$ 468,362
Sales to affiliates	22,949	21,839	3,140	—	(47,928)	—
Purchased gas, NGLs and crude oil	(121,910)	(54,460)	(159,991)	(79,916)	47,928	(368,349)
Operating expenses	(8,487)	(13,853)	(6,847)	(9,903)	—	(39,090)
Segment profit	$ 12,268	$ 25,655	$ 17,629	$ 5,371	$ —	$ 60,923
Loss on derivatives	$ (584)	$ (510)	$ (271)	$ (269)	$ —	$ (1,634)
Depreciation, amortization and impairments	$ (3,149)	$ (19,887)	$ (78,652)	$ (3,264)	$ (829)	$ (105,781)
Capital expenditures	$ 10,842	$ 4,821	$ 101,406	$ 5,412	$ 1,464	$ 123,945
Identifiable assets	$ 282,088	$ 989,583	$ 869,156	$ 327,496	$ 148,031	$ 2,616,354
Three Months Ended September 30, 2012						
Sales to external customers	$ 141,977	$ 65,606	$ 184,427	$ 52,937	$ —	$ 444,947
Sales to affiliates	50,304	22,278	35,209	—	(107,791)	—
Purchased gas, NGLs and crude oil	(166,374)	(41,807)	(204,267)	(40,545)	107,791	(345,202)
Operating expenses	(8,468)	(14,255)	(7,306)	(5,522)	—	(35,551)
Segment profit	$ 17,439	$ 31,822	$ 8,063	$ 6,870	$ —	$ 64,194
Gain (loss) on derivatives	$ (498)	$ (293)	$ 32	$ —	$ —	$ (759)
Depreciation, amortization and impairments	$ (4,360)	$ (21,508)	$ (16,503)	$ (2,164)	$ (524)	$ (45,059)
Capital expenditures	$ 1,596	$ 7,596	$ 34,064	$ 556	$ 5,573	$ 49,385
Identifiable assets	$ 280,959	$ 1,067,591	$ 538,427	$ 318,258	$ 144,192	$ 2,349,427
Nine Months Ended September 30, 2013						
Sales to external customers	$ 372,499	$ 230,938	$ 550,811	$ 214,392	$ —	$ 1,368,640
Sales to affiliates	68,854	55,309	19,659	—	(143,822)	—
Purchased gas, NGLs and crude oil	(377,937)	(160,254)	(502,680)	(171,415)	143,822	(1,068,464)
Operating expenses	(23,961)	(40,499)	(22,067)	(26,677)	—	(113,204)
Segment profit	$ 39,455	$ 85,494	$ 45,723	$ 16,300	$ —	$ 186,972
Gain (loss) on derivatives	$ 370	$ (1,558)	$ (25)	$ (449)	$ —	$ (1,662)
Depreciation, amortization and impairments	$ (9,421)	$ (59,528)	$ (94,842)	$ (8,355)	$ (1,996)	$ (174,142)
Capital expenditures	$ 27,010	$ 12,073	$ 329,071	$ 14,345	$ 7,406	$ 389,905
Identifiable assets	$ 282,088	$ 989,583	$ 869,156	$ 327,496	$ 148,031	$ 2,616,354
Nine Months Ended September 30, 2012						
Sales to external customers	$ 410,154	$ 191,523	$ 610,694	$ 52,937	$ —	$ 1,265,308
Sales to affiliates	183,529	70,988	120,997	—	(375,514)	—
Purchased gas, NGLs and crude oil	(509,196)	(123,284)	(677,996)	(40,545)	375,514	(975,507)
Operating expenses	(25,164)	(41,549)	(21,693)	(5,522)	—	(93,928)
Segment profit	$ 59,323	$ 97,678	$ 32,002	$ 6,870	$ —	$ 195,873
Gain (loss) on derivatives	$ 4,145	$ (2,709)	$ 541	$ —	$ —	$ 1,977

Depreciation, amortization and impairments	$ (10,695)	$ (62,950)	$ (32,530)	$ (2,164)	$ (1,768)	$ (110,107)
Capital expenditures	$ 3,484	$ 41,050	$ 79,981	$ 556	$ 7,109	$ 132,180
Identifiable assets	$ 280,959	$ 1,067,591	$ 538,427	$ 318,258	$ 144,192	$ 2,349,427

The following table reconciles the segment profits reported above to the operating income as reported in the condensed consolidated statements of operations (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Segment profits	$ 60,923	$ 64,194	$ 186,972	$ 195,873
General and administrative expenses	(15,605)	(16,470)	(50,053)	(44,398)
Gain (loss) on derivatives	(1,634)	(759)	(1,662)	1,977
Gain (loss) on sale of property	270	(109)	175	395
Depreciation, amortization and impairments	(105,781)	(45,059)	(174,142)	(110,107)
Operating income (loss)	$ (61,827)	$ 1,797	$ (38,710)	$ 43,740

(11) Immaterial Correction of Prior Period Financial Statements

During the period ended June 30, 2013, the Partnership determined certain immaterial corrections were required for previously-issued financial statements as discussed below. The corrections did not impact the Partnership's operating income and were not considered material to the Partnership's revenues and costs for the applicable periods.

The Partnership determined that revenues and purchased gas costs related to a new processing arrangement were improperly reduced from revenue and purchased gas costs which resulted in equal understatements of revenues and purchased gas costs in its previously-issued financial statements for the three and nine months ended September 30, 2012. As a result both revenues and purchased gas were understated by $38.0 million and $135.4 million for the three and nine months ended September 30, 2012, respectively. The following table reflects the revenues, purchased gas costs and total operating costs and expenses as previously reported and as adjusted for the three and nine months ended September 30, 2012 (in thousands):

	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2012
As previously reported:		
Total revenues	$ 406,968	$ 1,129,871
Purchased gas, NGLs and crude oil	$ 307,223	$ 840,070
Total operating costs and expenses	$ 405,171	$ 1,086,131
Operating income	$ 1,797	$ 43,740
As adjusted:		
Total revenues	$ 444,947	$ 1,265,308
Purchased gas, NGLs and crude oil	$ 345,202	$ 975,507
Total operating costs and expenses	$ 443,150	$ 1,221,568
Operating income	$ 1,797	$ 43,740

(12) Subsequent Events

On October 21, 2013, the Partnership and CEI entered into agreements with Devon Energy Corporation (“Devon”) to combine substantially all of Devon’s U.S. midstream assets with our assets to form a new midstream business. The new business will consist of two publicly traded entities: the Master Limited Partnership and a General Partner entity (collectively “the New Company”). The transaction is expected to be completed during the first quarter of 2014 pending approval by the CEI's stockholders.

On October 28, 2013, the Partnership announced it will expand its natural gas gathering and processing system in the Permian Basin by constructing a new natural gas processing complex and rich gas gathering pipeline system. The initial investment of approximately $140.0 million will include treating, processing and gas takeaway solutions for regional producers. The project, which will be fully owned by the Partnership, is supported by long-term, fee-based contracts. The entire project is scheduled to be completed and operational in the summer of 2014.

Item 2. ***Management's Discussion and Analysis of Financial Condition and Results of Operations***

You should read the following discussion of our financial condition and results of operations in conjunction with the financial statements and notes thereto included elsewhere in this report.

Overview

We are a Delaware limited partnership formed on July 12, 2002. We primarily focus on providing midstream energy services, including gathering, processing, transmission and marketing, to producers of natural gas, natural gas liquids ("NGLs") and crude oil. We also provide crude oil, condensate and brine disposal services to producers. Our midstream energy asset network includes approximately 3,500 miles of pipelines, ten natural gas processing plants, four fractionators, 3.1 million barrels of NGL cavern storage, rail terminals, barge terminals, truck terminals and a fleet of approximately 100 trucks. We manage and report our activities primarily according to geography. We have five reportable segments: (1) South Louisiana processing, crude and NGL, or PNGL, which includes our processing and NGL assets in South Louisiana; (2) Louisiana, or LIG, which includes our pipelines and processing plants located in Louisiana; (3) North Texas, or NTX, which includes our activities in the Barnett Shale and the Permian Basin; (4) Ohio River Valley, or ORV, which includes our activities in the Utica and Marcellus Shales; and (5) Corporate Segment, or Corporate, which includes our equity investment in Howard Energy Partners, or HEP, in the Eagle Ford Shale and our general partnership property and expenses.

We manage our operations by focusing on gross operating margin because our business is generally to purchase and resell natural gas, NGLs and crude oil for a margin or to gather, process, transport or market natural gas, NGLs and crude oil for a fee. In addition, we earn a volume based fee for providing crude oil transportation and brine disposal services. We define gross operating margin as operating revenue minus cost of purchased gas, NGLs and crude oil. Gross operating margin is a non-generally accepted accounting principles, or non-GAAP, financial measure and is explained in greater detail under "Non-GAAP Financial Measures" below.

Our gross operating margins are determined primarily by the volumes of natural gas gathered, transported, purchased and sold through our pipeline systems, processed at our processing facilities, the volumes of NGLs handled at our fractionation facilities, the volumes of crude oil handled at our crude terminals, the volumes of crude oil gathered, transported, purchased and sold and the volume of brine disposed. We generate revenues from seven primary sources:

- purchasing and reselling or transporting natural gas on the pipeline systems we own;
- processing natural gas at our processing plants;
- fractionating and marketing the recovered NGLs;
- providing compression services;
- purchasing and reselling crude oil and condensate;
- providing crude oil transportation and terminal services; and
- providing brine disposal services.

We generally gather or transport gas owned by others through our facilities for a fee, or we buy natural gas from a producer, plant or shipper at either a fixed discount to a market index or a percentage of the market index, then transport and resell the natural gas at the market index. We attempt to execute all purchases and sales substantially concurrently, or we enter into a future delivery obligation, thereby establishing the basis for the margin we will receive for each natural gas transaction. Our gathering and transportation margins related to a percentage of the index price can be adversely affected by declines in the price of natural gas. We are also party to certain long-term gas sales commitments that we satisfy through supplies purchased under long-term gas purchase agreements. When we enter into those arrangements, our sales obligations generally match our purchase obligations. However, over time the supplies that we have under contract may decline due to reduced drilling or other causes and we may be required to satisfy the sales obligations by buying additional gas at prices that may exceed the prices received under the sales commitments. In our purchase/sale transactions, the resale price is generally based on the same index at which the gas was purchased. However, on occasion we have entered into certain purchase/sale transactions in which the purchase price is based on a production-area index and the sales price is based on a market-area index, and we capture the difference in the indices (also referred to as basis spread), less the transportation expenses from the two areas, as our margin. Changes in the basis spread can increase or decrease our margins.

One contract (the "Delivery Contract") has a term to 2019 that obligates us to supply approximately 150,000 million British thermal units per day ("MMBtu/d") of gas. At the time that we entered into the Delivery Contract in 2008, we had dedicated supply sources in the Barnett Shale that exceeded the delivery obligations under the Delivery Contract. Our agreements with these suppliers generally provided that the purchase price for the gas was equal to a portion of our sales price for such gas less certain fees and costs. Accordingly, we were initially able to generate a positive margin under the Delivery Contract. However, since entering into the Delivery Contract, there has been both (1) a reduction in the gas available under our supply contracts and (2) the discovery of other shale reserves, most notably the Haynesville and the Marcellus Shales, which has increased the supplies available to east coast markets and reduced the basis spread between north Texas-area production and the market indices used in the Delivery Contract. Due to these factors, we have had to purchase a portion of the gas necessary to fulfill our obligations under the Delivery Contract at market prices, resulting in negative margins under the Delivery Contract.

We have recorded a loss of approximately $13.5 million during the nine months ended September 30, 2013 on the Delivery Contract. We currently expect that we will record an additional loss of approximately $4.0 million to $6.0 million on the Delivery Contract for the remainder of the year ending December 31,2013 and a loss of $20.0 million to $23.0 million during the year ended December 31, 2014. These estimates are based on forward prices, basis spreads and other market assumptions as of September 30, 2013. These assumptions are subject to change if market conditions change during the remainder of2013, and actual results under the Delivery Contract in2013 and 2014 could be substantially different from our current estimates, which may result in a greater loss than currently estimated.

We generally gather or transport crude oil owned by others by rail, truck, pipeline and barge facilities for a fee, or we buy crude oil from a producer at a fixed discount to a market index, then transport and resell the crude oil at the market index. We execute all purchases and sales substantially concurrently, thereby establishing the basis for the margin we will receive for each crude oil transaction. Additionally, we provide crude oil, condensate and brine services on a volume basis.

We also realize gross operating margins from our processing services primarily through three different contract arrangements: processing margins ("margin"), percentage of liquids ("POL") or fixed-fee based. Under margin contract arrangements our gross operating margins are higher during periods of high liquid prices relative to natural gas prices. Gross operating margin results under POL contracts are impacted only by the value of the liquids produced with margins higher during periods of higher liquids prices. Under fixed-fee based contracts our gross operating margins are driven by throughput volume. See "Item 3. Quantitative and Qualitative Disclosures about Market Risk — Commodity Price Risk."

Operating expenses are costs directly associated with the operations of a particular asset. Among the most significant of these costs are those associated with direct labor and supervision, property insurance, property taxes, repair and maintenance expenses, contract services and utilities. These costs are normally fairly stable across broad volume ranges and therefore do not normally decrease or increase significantly in the short term with decreases or increases in the volume of gas, liquids or crude oil moved through or by the asset.

Our general and administrative expenses are dictated by the terms of our partnership agreement. These expenses include the costs of employee, officer and director compensation and benefits properly allocable to us, fees, services and other transaction costs related to acquisitions, and all other expenses necessary or appropriate to the conduct of business and allocable to us. Our partnership agreement provides that our General Partner determines the expenses that are allocable to us in any reasonable manner determined by our General Partner in its sole discretion.

Recent Developments

Devon Energy Transaction. On October 21, 2013, the Partnership and its wholly-owned subsidiary, Crosstex Energy Services, L.P. ("Crosstex Energy Services") entered into a Contribution Agreement (the "Contribution Agreement") with Devon Energy Corporation ("Devon") and certain of its wholly-owned subsidiaries pursuant to which two of Devon's subsidiaries would contribute to Crosstex Energy Services 50% of the outstanding equity interests in Devon Midstream Holdings, L.P. ("Midstream Holdings"), a wholly-owned subsidiary of Devon and all of the outstanding equity interests in Devon Midstream Holdings GP, L.L.C., the general partner of Midstream Holdings ("Midstream Holdings GP" and, together with Midstream Holdings and their subsidiaries, the "Midstream Group Entities") in exchange for the issuance by the Partnership of 120,542,441 units representing a new class of limited partnership interests in the Partnership (collectively, the "Contribution"). At the effective time of the Contribution, the Midstream Group Entities will own Devon's midstream assets in the Barnett Shale in North Texas, the Cana and Arkoma Woodford Shales in Oklahoma and Devon's interest in Gulf Coast Fractionators in Mt. Belvieu, Texas.

In connection with the Contribution Agreement, CEI entered into an Agreement and Plan of Merger (the "Merger Agreement") with Devon and certain of its wholly-owned subsidiaries, New Public Rangers, L.L.C., a holding company newly formed by Devon ("New Public Rangers"), Rangers Merger Sub, Inc., a wholly-owned subsidiary of New Public Rangers ("Rangers Merger Sub"), and Boomer Merger Sub, Inc., a wholly-owned subsidiary of New Public Rangers ("Boomer Merger Sub"), pursuant to which Rangers Merger Sub will merge with and into CEI, and Boomer Merger Sub will merge with and into New Acacia (collectively, the "Mergers"), with CEI and New Acacia surviving as wholly-owned subsidiaries of New Public Rangers. New Acacia will own the remaining 50% limited partner interest in Midstream Holdings. Devon will own the managing member of New Public Rangers, and New Public Rangers will indirectly own 100% of our General Partner.

The closing of the Contribution is subject to the satisfaction of a number of conditions, including, but not limited to, (i) the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended and (ii) the closing of the Mergers. The Contribution Agreement also contains customary termination provisions and will automatically terminate upon any termination of the Merger Agreement.

Bearkat Natural Gas Gathering and Processing System. On October 28, 2013, the Partnership announced it will expand its natural gas gathering and processing system in the Permian Basin by constructing a new natural gas processing complex and rich gas gathering pipeline system. The initial investment of approximately $140.0 million will include treating, processing and gas takeaway solutions for regional producers. The project, which will be fully owned by the Partnership, is supported by long-term, fee-based contracts.

The new-build processing complex, called Bearkat, will be strategically located near the Partnership's existing Deadwood joint venture assets in Glasscock County, Texas. The processing plant will have an initial capacity of 60 million cubic feet per day (MMcf/d), increasing the Partnership's total operated processing capacity in the Permian to approximately 115 MMcf/d. The Partnership will also construct a 30-mile high-pressure gathering system upstream of the Bearkat complex to provide additional gathering capacity for producers in Glasscock and Reagan counties. The entire project is scheduled to be completed and operational in the summer of 2014.

Black Run Rail Terminal. In June 2013, we re-activated our Black Run rail loading terminal located in Frazeysburg, Ohio on the Ohio Central Railroad ("OHCR"), allowing for the transport of various grades of crude oil and condensate. The Black Run facility is a 20-car rail rack with tracking gangways designed to top load multiple products, including condensate and various grades of crude oil, at a rate of 24,000 barrels per day ("Bbls/d"). The Black Run rail terminal moves condensate out of the ORV region to refinery and petrochemical markets.

The OHCR is a 70-mile short line freight railroad that interchanges with the Columbus and Ohio River Railroad, CSX Transportation, Norfolk Southern, Ohio Southern Railroad and Wheeling and Lake Erie Railway. The Black Run terminal, which is adjacent to our oil gathering pipeline, leverages our existing tankage and piping, as well as the capabilities of our extensive truck fleet in the Ohio River Valley.

Riverside Crude Facility Expansion. In June 2013, we completed the Phase II expansion of our Riverside facility located on the Mississippi River in southern Louisiana. The Riverside facility's capacity to transload crude oil from railcars to our barge facility increased to approximately 15,000 Bbls/d of crude oil. Phase II additions to the Riverside facility include a 100,000 barrel above-ground crude oil storage tank, a rail spur with a 26-spot crude railcar unloading rack and a crude offloading facility with pumps and metering as well as a truck unloading bay. As part of the Phase II expansion, the Riverside facility was modified so that sour crude can be unloaded in addition to sweet crude.

Cajun-Sibon Phases I and II. In Louisiana, we are transforming our business that has been historically focused on processing offshore natural gas to a business that is focused on NGLs with additional opportunities for growth from new onshore supplies of NGLs. The Louisiana petrochemical market has historically relied on liquids from offshore production; however, the decrease in offshore production and increase in onshore rich gas production have changed the market structure. Cajun-Sibon Phases I and II will work to bridge the gap between supply, which aggregates in the Mont Belvieu area, and demand, located in the Mississippi River corridor of Louisiana, thereby building a strategic NGL position in this region. We currently estimate that the total capital investment for Cajun-Sibon Phases I and II will be approximately $750.0 million.

We began this transformation by restarting our Eunice fractionator during 2011 at a rate of 15,000 Bbls/d of NGLs. This is a pivotal asset for Cajun-Sibon Phase I as we are expanding this facility to a rate of 55,000 Bbls/d. Phase I of our pipeline extension project was completed in October 2013 and connects Mont Belvieu supply lines in east Texas to Eunice, providing a direct link to our fractionators in south Louisiana markets. The Phase I Eunice fractionator expansion, which was completed in early November 2013, has increased our interconnected fractionation capacity in Louisiana to approximately 97,000 Bbls/d of raw-make NGLs. We expect the Phase I facilities to ramp-up to full volumes during the fourth quarter of 2013.

Cajun-Sibon Phase II will further enhance our Louisiana NGL business with significant additions to the Cajun-Sibon Phase I NGL pipeline extension and Eunice expansion. Under Phase II we will add pumping stations on the Phase I pipeline extension to increase its NGL supply capacity from approximately 70,000 Bbls/d to approximately 120,000 Bbls/d, construct a new 100,000 Bbl/d fractionator at the Plaquemine gas processing plant site and extend the Phase I NGL pipeline from Eunice to the new Plaquemine fractionator. We expect Phase II will be in service during the second half of 2014.

Issuance of Common Units. In June 2013, we issued 8,280,000 common units representing limited partner interests in the Partnership (including 1,080,000 common units issued pursuant to the exercise of the underwriters' option to purchase additional common units) at a public offering price of $20.33 per common unit for net proceeds of $162.0 million. The net proceeds from the common unit offering were used for capital expenditures for currently identified projects, including the Cajun-Sibon natural gas liquids pipeline expansion, to repay bank borrowings and for general partnership purposes.

In January 2013, we issued 8,625,000 common units representing limited partner interests in the Partnership at a public offering price of $15.15 per common unit for net proceeds of $125.4 million. Concurrently with the public offering, we issued 2,700,000 common units representing limited partner interest in the Partnership at a price of $14.55 per unit for net proceeds of $39.2 million. The net proceeds from both common unit offerings were used for capital expenditures for currently identified projects, to repay bank borrowings and for general partnership purposes.

In May 2013, we entered into an Equity Distribution Agreement ("EDA") with BMO Capital Markets Corp. (“BMOCM”). This EDA replaced the previous equity distribution agreement entered into in March 2013 between BMOCM and us. Pursuant to the terms of the EDA, we may from time to time through BMOCM, as its sales agent, sell common units representing limited partner interests having an aggregate offering price of up to $75.0 million. Through September 30, 2013, we sold an aggregate of 3,370,486 common units under the EDA and prior equity distribution agreement generating proceeds of approximately $62.9 million (net of approximately $0.9 million of commissions to BMOCM). We used the net proceeds for general partnership purposes, including working capital, capital expenditures and repayments of indebtedness.

Other Developments. HEP is continuing to expand its midstream assets in the Eagle Ford Shale in south Texas. We contributed an additional $22.3 million to HEP during the nine months ended September 30, 2013 to fund our 30.6% share of HEP’s expansion costs. We also received cash distributions totaling $13.1 million from HEP during the nine months ended September 30, 2013. We are obligated to contribute additional funds to HEP upon one or more requests made by HEP. We expect that as HEP makes additional distributions to us and its other investors from its existing operations, HEP will request that we make additional capital contributions to fund its ongoing expansion efforts.

Non-GAAP Financial Measures

We include the following non-GAAP financial measures: Adjusted earnings before interest, taxes, depreciation and amortization, or adjusted EBITDA, and gross operating margin.

We define adjusted EBITDA as net income plus interest expense, provision for income taxes, depreciation and amortization expense, impairments, stock-based compensation, (gain) loss on noncash derivatives, distribution from limited liability company and noncontrolling interest; less gain on sale of property and equity in income (loss) of limited liability company. Adjusted EBITDA is used as a supplemental performance measure by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others, to assess:

- financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness and make cash distributions to our unitholders and our General Partner;
- our operating performance and return on capital as compared to those of other companies in the midstream energy sector, without regard to financing methods or capital structure; and
- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

Adjusted EBITDA is one of the critical inputs into the financial covenants within our credit facility. The rates we pay for borrowings under our credit facility are determined by the ratio of our debt to adjusted EBITDA. The calculation of these ratios allows for further adjustments to adjusted EBITDA for recent material projects and acquisitions and dispositions.

Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP. Adjusted EBITDA may not be comparable to similarly titled measures of other companies because other entities may not calculate adjusted EBITDA in the same manner.

Adjusted EBITDA does not include interest expense, income taxes or depreciation and amortization expense. Because we have borrowed money to finance our operations, interest expense is a necessary element of our costs and our ability to generate cash available for distribution. Because we use capital assets, depreciation and amortization are also necessary elements of our costs. Therefore, any measures that exclude these elements have material limitations. To compensate for these limitations, we believe that it is important to consider both net earnings determined under GAAP, as well as adjusted EBITDA, to evaluate our overall performance.

The following table provides a reconciliation of net loss to adjusted EBITDA:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(In millions)			
Net income (loss) attributable to Crosstex Energy, L.P.	$ (78.8)	$ (16.1)	$ (95.4)	$ (15.6)
Interest expense	16.4	23.2	54.9	63.9
Depreciation and amortization	33.2	45.1	101.6	110.1
Impairments	72.6	—	72.6	—
Earnings in (income) loss of limited liability company	0.1	(1.5)	0.1	(1.5)
Distribution from limited liability company	4.3	—	13.1	—
(Gain) loss on sale of property	(0.3)	0.1	(0.2)	(0.4)
Stock-based compensation	3.0	2.5	11.1	7.5
Other (a)	2.0	1.9	3.2	(1.7)
Adjusted EBITDA	$ 52.5	$ 55.2	$ 161.0	$ 162.3

(a) Includes financial derivatives marked-to-market; income taxes; acquisition cost; and non-controlling interest.

We define gross operating margin, generally, as revenues less cost of purchased gas, NGLs and crude oil. We present gross operating margin by segment in "Results of Operations". We disclose gross operating margin in addition to total revenue because it is the primary performance measure used by our management. We believe gross operating margin is an important measure because our business is generally to purchase and resell natural gas and crude oil for a margin or to gather, process, transport or market natural gas, NGLs and crude oil for a fee. Operating expense is a separate measure used by management to evaluate operating performance of field operations. Direct labor and supervision, property insurance, property taxes, repair and maintenance, utilities and contract services comprise the most significant portion of our operating expenses. We do not deduct operating expenses from total revenue in calculating gross operating margin because these expenses are largely independent of the volumes we transport or process and fluctuate depending on the activities performed during a specific period. As an indicator of our operating performance, gross operating margin should not be considered an alternative to, or more meaningful than, net income as determined in accordance with GAAP. Our gross operating margin may not be comparable to similarly titled measures of other companies because other entities may not calculate these amounts in the same manner.

The following table provides a reconciliation of gross operating margin to operating income (loss):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(In millions)			
Total gross operating margin	$ 100.0	$ 99.8	$ 300.2	$ 289.8
Add (deduct):				
Operating expenses	(39.1)	(35.6)	(113.2)	(93.9)
General and administrative expenses	(15.6)	(16.5)	(50.1)	(44.4)
Gain (loss) on sale of property	0.3	(0.1)	0.2	0.4
Gain (loss) on derivatives	(1.6)	(0.8)	(1.7)	1.9
Depreciation, amortization and other	(33.2)	(45.0)	(101.5)	(110.1)
Impairments	(72.6)	—	(72.6)	—
Operating income (loss)	$ (61.8)	$ 1.8	$ (38.7)	$ 43.7

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Results of Operations

Set forth in the table below is certain financial and operating data for the periods indicated, which includes our July 2012 acquisition of the ORV assets from the date of acquisition. We manage our operations by focusing on gross operating margin which we define as operating revenue less cost of purchased gas, NGLs and crude oil as reflected in the table below.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
		(As Adjusted)		(As Adjusted)
	(Dollars in millions)			
LIG Segment				
Revenues	$ 142.7	$ 192.3	$ 441.4	$ 593.7
Purchased gas and NGLs	(121.9)	(166.4)	(377.9)	(509.2)
Total gross operating margin	$ 20.8	$ 25.9	$ 63.5	$ 84.5
NTX Segment				
Revenues	$ 93.9	$ 87.9	$ 286.2	$ 262.5
Purchased gas and NGLs	(54.4)	(41.8)	(160.3)	(123.3)
Total gross operating margin	$ 39.5	$ 46.1	$ 125.9	$ 139.2
PNGL Segment				
Revenues	$ 184.5	$ 219.7	$ 570.5	$ 731.7
Purchased gas, NGLs and crude oil	(160.0)	(204.3)	(502.7)	(678.0)
Total gross operating margin	$ 24.5	$ 15.4	$ 67.8	$ 53.7
ORV Segment				
Revenues	$ 95.2	$ 52.9	$ 214.4	$ 52.9
Purchased crude oil	(80.0)	(40.5)	(171.4)	(40.5)
Total gross operating margin	$ 15.2	$ 12.4	$ 43.0	$ 12.4
Corporate				
Revenues	$ (47.9)	$ (107.8)	$ (143.8)	$ (375.5)
Purchased gas and NGLs	47.9	107.8	143.8	375.5
Total gross operating margin	$ —	$ —	$ —	$ —
Total				
Revenues	$ 468.4	$ 445.0	$ 1,368.7	$ 1,265.3
Purchased gas, NGLs and crude oil	(368.4)	(345.2)	(1,068.5)	(975.5)
Total gross operating margin	$ 100.0	$ 99.8	$ 300.2	$ 289.8
Midstream Volumes:				
LIG				
Gathering and Transportation (MMBtu/d)	457,000	741,000	494,000	814,000
Processing (MMBtu/d)	256,000	215,000	254,000	241,000
NTX				
Gathering and Transportation (MMBtu/d)	1,032,000	1,163,000	1,060,000	1,177,000
Processing (MMBtu/d)	374,000	386,000	388,000	353,000
PNGL				
Processing (MMBtu/d)	392,000	602,000	416,000	769,000
NGL Fractionation (Gals/d)	1,187,000	1,350,000	1,171,000	1,284,000
ORV*				
Crude Oil Handling (Bbls/d)	14,000	12,000	11,000	12,000
Brine Disposal (Bbls/d)	8,000	8,000	8,000	8,000

* Crude oil handling from PNGL is included in ORV reported volumes.

Three Months Ended September 30, 2013 Compared to Three Months Ended September 30, 2012

Gross Operating Margin. Gross operating margin was $100.0 million for the three months ended September 30, 2013 compared to $99.8 million for the three months ended September 30, 2012, an increase of $0.2 million, or 0.2%. The overall increase was due to, increased south Louisiana NGL fractionation and marketing activity and an increase from our ORV assets. The following provides additional details regarding this change in gross operating margin:

- The ORV segment contributed an increase of $2.8 million to our gross operating margin for the three months ended September 30, 2013. The crude oil and condensate handling activity margin increased $2.4 million to $10.9 million for the third quarter of 2013 as compared to the third quarter of 2012 due to an increase in condensate volumes. Gross operating margins from brine disposal and handling increased by $0.5 million to $4.4 million for the third quarter of 2013 as compared to the third quarter 2012.

- The PNGL segment had a gross operating margin increase of $9.1 million for the three months ended September 30, 2013 compared to the three months ended September 30, 2012. Our NGL fractionation and marketing activities contributed $6.8 million of the gross operating margin increase due to increased NGL volumes from truck and rail activity. The PNGL crude oil terminal activity in south Louisiana contributed $1.0 million due to an increase in crude activity. The south Louisiana processing plants gross operating margin increased $1.3 million from third party opportunity processing during July and August 2013 due to third-party system repairs which diverted liquids-rich gas by our plant.

- The NTX segment had a decrease in gross operating margin of $6.6 million for the three months ended September 30, 2013 compared to the three months ended September 30, 2012. Gross operating margin decreased by $6.6 million from our transmission and gathering assets due to a decline in our throughput volumes combined with a reduction in gathering rates under certain contracts, including a contract with a major producer in north Texas.

- The LIG segment had a decrease in gross operating margin of $5.1 million for the three months ended September 30, 2013 compared to the three months ended September 30, 2012. Gross operating margins decreased by $0.7 million from our Gibson and Plaquemine plants and gas processed for our account by a third-party processor due to a weaker processing environment during 2013 as compared to 2012. Gross operating margins decreased by $4.4 million on the gathering and transmission assets due to sales volumes lost related to the Bayou Corne sinkhole, lost opportunity sales volumes due to lower processing margins and a reduction in treating and blending volumes.

Operating Expenses. Operating expenses were $39.1 million for the three months ended September 30, 2013 compared to $35.6 million for the three months ended September 30, 2012, an increase of $3.5 million, or 10.0%. The primary contributors to the increase are as follows:

- our labor and benefits expenses increased by $1.8 million related to an increase in employee headcount due to increased activity in our ORV and PNGL segments;

- our rents, lease and vehicle expenses increased by $0.6 million primarily related to an increase in fuel and maintenance cost for additional vehicles in our ORV segment; and

- our regulatory and tax expenses increased $1.2 million as a result of increased ad valorem tax expenses on our ORV assets.

General and Administrative Expenses. General and administrative expenses were $15.6 million for the three months ended September 30, 2013 compared to $16.5 million for the three months ended September 30, 2012, a decrease of $0.9 million, or 5.3%. The primary contributors to the total decrease are as follows:

- our labor and benefits expenses decreased by $0.6 million due to a decrease in our estimated bonus accrual during the third quarter of 2013 that more than offset our increase in labor costs arising from an increase in employee headcount;

- our fees and services expenses decreased by $0.9 million due to a decrease in legal and other professional fees; and

- our stock based compensation expense increased by $0.4 million due to an increase in headcount.

(Gain)/Loss on Derivatives. We had a loss on derivatives of $1.6 million for the three months ended September 30, 2013 compared to a loss of $0.8 million for the three months ended September 30, 2012. The derivative transaction types contributing to the net loss are as follows (in millions):

	Three Months Ended September 30,			
	2013		2012	
	Total	Realized	Total	Realized
Basis swaps	$ 0.1	$ 0.3	$ 0.1	$ 1.3
Processing margin hedges	0.5	(0.4)	0.3	(0.8)
Liquids Swaps - non-designated	0.5	—	0.3	—
Storage/Inventory Swaps	0.4	0.7	0.1	(0.3)
Other	0.1	—	—	0.1
Net loss on derivatives	$ 1.6	$ 0.6	$ 0.8	$ 0.3

Depreciation and Amortization. Depreciation and amortization expenses were $33.2 million for the three months ended September 30, 2013 compared to $45.1 million for the three months ended September 30, 2012, a decrease of $11.9 million, or 26.3%. This decrease includes $8.6 million related to accelerated depreciation and amortization of the Sabine Pass Plant included in the quarter ended September 30, 2012, $2.5 million of decreased intangible amortization due to the Eunice processing plant impairment discussed below, and $1.7 million of decreased intangible amortization related to the revision in future estimated throughput volumes attributable to the dedicated acreage purchased with our gathering system in North Texas. These decreases were partially offset by additional depreciation due to net asset additions.

Impairment. Impairment expense was $72.6 million for the three months ended September 30, 2013. The impairment relates to the termination of customer contracts associated with the Eunice processing plant which was shut-down in August 2013.

Interest Expense. Interest expense was $16.4 million for the three months ended September 30, 2013 compared to $23.2 million for the three months ended September 30, 2012, a decrease of $6.8 million, or 29.3%. Net interest expense consists of the following (in millions):

	Three Months Ended September 30,	
	2013	2012
Senior notes	$ 20.5	$ 20.5
Bank credit facility	1.4	1.4
Capitalized interest (1)	(8.5)	(1.0)
Amortization of debt issue costs and discount	2.0	1.9
Other	1.0	0.4
Total	$ 16.4	$ 23.2

(1) The increase in capitalized interest is primarily related to project expansions in our PNGL segment.

Equity in income (loss) of limited liability company. Equity in losses of limited liability company was $0.1 million for the three months ended September 30, 2013 compared to earnings of $1.5 million for the three months ended September 30, 2012. The decrease of $1.6 million of equity in earnings relates to our HEP equity investment.

Other Income. Other income was less than $0.1 million for the three months ended September 30, 2013 compared to $4.4 million for the three months ended September 30, 2012. Our 2012 other income included a $3.0 million net gain related to the assignment to a third party of our rights, title and interest in a contract for the construction of a processing plant. In addition, we settled certain liabilities associated with sold assets for less than the accrued liabilities resulting in a $1.3 million gain in 2012.

Nine Months Ended September 30, 2013 Compared to Nine Months Ended September 30, 2012

Gross Operating Margin. Gross operating margin was $300.2 million for the nine months ended September 30, 2013 compared to $289.8 million for the nine months ended September 30, 2012, resulting in an increase of $10.4 million, or 3.6%. The overall increase was due to the July 2012 acquisition of the ORV assets and increased south Louisiana NGL fractionation and marketing activity. The following provides additional details regarding this change in gross operating margin:

- The ORV gross margin was $43.0 million for the nine months ended September 30, 2013 which includes a full nine months of ORV operations compared to $12.4 million for the nine months ended September 30, 2012, which only included operations for the three months in 2012 from the date of acquisition, an increase of $30.6 million. Gross operating margins for the nine months ended September 30, 2013 from crude oil and condensate handling and brine disposal and handling totaled $29.0 million and $14.0 million, respectively.

- The PNGL segment had a gross operating margin increase of $14.1 million for the nine months ended September 30, 2013 compared to the nine months ended September 30, 2012. Our NGL fractionation and marketing activities contributed $20.6 million of the gross operating margin increase due to improved margins from seasonal pricing spreads and increased NGL volumes from truck and rail activity. The PNGL segment also includes our crude oil terminal activity in south Louisiana, which contributed $2.0 million of gross operating margin increase. These increases were offset by a combined gross operating margin decrease of $8.5 million from our south Louisiana processing plants due to the less favorable processing environment which caused a significant decline in volumes processed through the plants as well as declines in margins earned on those volumes.

- The NTX segment had a decrease in gross operating margin of $13.3 million for the nine months ended September 30, 2013 compared to the nine months ended September 30, 2012. Gross operating margin increased by $4.6 million from our gas processing facilities primarily due to increased throughput on our Permian Basin system. This increase was offset by a decline in our gross operating margin of $17.8 million from the gathering and transmission assets due to a decline in our throughput volumes together with reduced gathering rates under certain contracts, including a contract with a major producer in north Texas.

- The LIG segment had a decrease in gross operating margin of $21.0 million for the nine months ended September 30, 2013 compared to the nine months ended September 30, 2012. Gross operating margins decreased by $6.1 million from our Gibson and Plaquemine plants and decreased by $3.5 million from gas processed for our account by a third-party processor due to a weaker processing environment during 2013 as compared to 2012. Gross operating margins decreased by $11.4 million on the gathering and transmission assets due to sales volumes lost related to the Bayou Corne sinkhole, loss of opportunity sales volumes due to lower processing margins and lower blending and treating volumes for the first nine months of 2013 as compared to same period in 2012. Although our north LIG system in the Haynesville Shale had volume declines, most of these volume declines were associated with gas transported under firm transportation agreements so we only realized a slight decrease in our transportation fee on our north LIG system.

Operating Expenses. Operating expenses were $113.2 million for the nine months ended September 30, 2013 compared to $93.9 million for the nine months ended September 30, 2012, an increase of $19.3 million, or 20.5%. This increase in operating expenses includes a total increase of $17.9 million related to the direct operating costs of ORV assets which are included for nine months during 2013 and only three months during 2012 (as set forth below). The primary contributors to the total increase are as follows:

- our labor and benefits expenses increased by $11.1 million related to an increase in employee headcount following the acquisition of our ORV assets and project expansion in our PNGL segment;

- our rents, lease and vehicle expenses increased by $4.0 million primarily related to the acquisition of our ORV assets; and

- our regulatory and tax expenses increased $2.5 million as a result of increased ad valorem tax expenses on our ORV assets.

General and Administrative Expenses. General and administrative expenses were $50.1 million for the nine months ended September 30, 2013 compared to $44.4 million for the nine months ended September 30, 2012, an increase of $5.7 million, or 12.7%. The primary contributors to the total increase are as follows:

- our labor and benefits expenses increased by $2.4 million primarily due to an increase in headcount primarily related to the acquisition of our ORV assets and activity related to project expansion in our PNGL segment;
- our stock based compensation expense increased by $3.1 million due to an increase in related headcount, including $2.0 million attributable to certain bonuses paid in March 2013 in the form of stock and unit awards that immediately vested;
- our communication related costs increased by $0.5 million due to network upgrades;
- our rent and office supply fees increased by $0.5 million due to increases in rent and office related costs; and
- our fees and services decreased by $1.5 million due to a decrease in legal and other professional fees.

(Gain)/Loss on Derivatives. We had a loss on derivatives of $1.7 million for the nine months ended September 30, 2013 compared to a gain of $2.0 million for the nine months ended September 30, 2012. The derivative transaction types contributing to the net (gain)/loss are as follows (in millions):

	Nine Months Ended September 30,			
	2013		2012	
	Total	Realized	Total	Realized
Basis swaps	$ 1.1	$ 1.9	$ 3.5	$ 3.5
Processing margin hedges	(0.5)	(1.5)	(3.9)	0.8
Liquids Swaps - non-designated	0.7	—	(1.1)	—
Storage/Inventory Swaps	0.3	0.5	(0.4)	(0.8)
Other	0.1	—	(0.1)	—
Net (gain) loss on derivatives	$ 1.7	$ 0.9	$ (2.0)	$ 3.5

Depreciation and Amortization. Depreciation and amortization expenses were $101.6 million for the nine months ended September 30, 2013 compared to $110.1 million for the nine months ended September 30, 2012, a decrease of $8.5 million, or 7.8%. This decrease includes accelerated depreciation and amortization of $9.8 million related to the Sabine Pass Plant included in 2012, $2.5 million of decreased intangible amortization related to the Eunice processing plant impairment discussed below, and $4.5 million of decreased intangible amortization related to the revision in future estimated throughput volumes attributable to the dedicated acreage purchased with our gathering system in North Texas. These decreases were partially offset by $8.3 million of additional depreciation due to net asset additions, including $6.2 million related to the July 2012 acquisition of the ORV assets for the nine months in 2013 as compared to three months in 2012.

Impairment. Impairment expense was $72.6 million for nine months ended September 30, 2013. The impairment relates to the termination of customers contracts associated with Eunice processing plant which was shut-down in August 2013.

Interest Expense. Interest expense was $54.9 million for the nine months ended September 30, 2013 compared to $63.9 million for the nine months ended September 30, 2012, a decrease of $9.1 million, or 14.2%. Net interest expense consists of the following (in millions):

	Nine Months Ended September 30,	
	2013	2012
Senior notes	$ 61.6	$ 54.6
Bank credit facility	4.1	5.2
Capitalized interest (1)	(18.6)	(2.2)
Amortization of debt issue costs and discount	6.0	5.4
Other	1.8	0.9
Total	$ 54.9	$ 63.9

(1) The increase in capitalized interest is primarily related to project expansions in our PNGL segment.

Equity in income (loss) of limited liability company. Equity in losses of limited liability company was $0.1 million for the nine months ended September 30, 2013 compared to earnings of $1.5 million for the nine months ended September 30, 2012. The decrease of $1.6 million of equity in earnings relates to our HEP equity investment.

Other Income. Other income was $0.4 million for the nine months ended September 30, 2013 compared to $4.5 million for the nine months ended September 30, 2012. Our 2012 other income included a $3.0 million net gain related to the assignment to a third party of our rights, title and interest in a contract for the construction of a processing plant. In addition, we settled certain liabilities associated with sold assets for less than the accrued liabilities resulting in a $1.3 million gain in 2012.

Income Tax Expense. Income tax expense was $2.1 million for the nine months ended September 30, 2013 compared to $1.5 million for the nine months ended September 30, 2012, an increase of $0.6 million. The increase is due to income taxes attributable to the new, wholly owned corporate entity that was formed to acquire the ORV assets.

Critical Accounting Policies

Impairment of Goodwill. Goodwill is the cost of an acquisition less the fair value of the net identifiable assets of the acquired business. We evaluate goodwill for impairment annually as of July 1, and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount. We first assess qualitative factors to evaluate whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as the basis for determining whether it is necessary to perform the two-step goodwill impairment test. We may elect to perform the two-step goodwill impairment test without completing a qualitative assessment. If a two-step process goodwill impairment test is elected or required, the first step involves comparing the fair value of the reporting unit, to which goodwill has been allocated, with its carrying amount. If the carrying amount of a reporting unit exceeds its fair value, the second step of the process involves comparing the implied fair value to the carrying value of the goodwill for that reporting unit. If the carrying value of the goodwill of a reporting unit exceeds the implied fair value of that goodwill, the excess of the carrying value over the implied fair value is recognized as an impairment loss. We evaluated our goodwill for impairment on July 1, 2013. Our goodwill impairment analysis performed on that date did not result in an impairment as the fair value of the ORV reporting unit substantially exceeded our carrying value, and subsequent to that date, no event has occurred indicating that the implied fair value of the reporting unit is less than the carrying value of our net assets.

Information regarding the Partnership's other Critical Accounting Policies is included in Item 7 of the Partnership's Annual Report on Form 10-K for the year ended December 31, 2012.

Liquidity and Capital Resources

Cash Flows from Operating Activities. Net cash provided by operating activities was $88.6 million for the nine months ended September 30, 2013 compared to $44.6 million for the nine months ended September 30, 2012. Income before non-cash income and expenses and changes in working capital for comparative periods were as follows (in millions):

	Nine Months Ended September 30,	
	2013	2012
Income before non-cash income and expenses	$ 93.6	$ 96.5
Changes in working capital	$ (5.0)	$ (51.9)

The change in working capital for 2013 and 2012 primarily relates to fluctuations in trade receivable and payable balances due to timing of collections and payments.

Cash Flows from Investing Activities. Net cash used in investing activities was $391.2 million for the nine months ended September 30, 2013 and $394.4 million for the nine months ended September 30, 2012. Our primary investing outflows were acquisition costs and capital expenditures, net of accrued amounts, as follows (in millions):

	Nine Months Ended September 30,	
	2013	2012
Growth capital expenditures	$ 387.2	$ 130.5
Maintenance capital expenditures	10.1	10.8
Acquisition	—	212.5
Investment in limited liability company	22.3	52.3
Total	$ 419.6	$ 406.1

Net cash provided by investing activities for the nine months ended September 30, 2013 includes proceeds of $18.5 million from our sale of the local distribution companies acquired in connection with our July 2012 acquisition of our ORV assets, which were classified as held for disposition on the balance sheet as of December 31, 2012, and $10.0 million of distributions from limited liability company in excess of earnings.

Cash Flows from Financing Activities. Net cash provided by financing activities was $302.5 million for the nine months ended September 30, 2013 and $328.2 million for nine months ended September 30, 2012. Our primary financing activities consist of the following (in millions):

	Nine Months Ended September 30,	
	2013	2012
Net borrowings (repayments) on bank credit facility	$ 5.0	$ (79.5)
2022 Notes borrowings	—	250.0
Net repayments under capital lease obligations	(2.4)	(2.3)
Debt refinancing costs	(2.0)	(6.9)
Common unit offerings	389.2	232.8

Successful completion of the Contribution and the Mergers would trigger an event of default under our credit facility and a mandatory repurchase offer under the terms of the indenture governing our 8.875% senior unsecured notes due 2018 (the “2018 Notes”) at a purchase price equal to 101% of the aggregate principal amount of the 2018 Notes repurchased, plus accrued and unpaid interest, if any. In certain circumstances, completion of the Contribution and the Mergers also could trigger a mandatory repurchase offer under the terms of the indenture governing our 7.125% senior unsecured notes due 2022 (the “2022 Notes”) if, within 90 days of consummation of the transactions, we experience a rating downgrade of the 2022 Notes by either Moody’s or S&P. We expect that, in connection with the closing of the Contribution and Mergers, we will seek an amendment to or waiver of the event of default provisions of our credit facility.

Distributions to unitholders and our general partner also represent a primary use of cash in financing activities. Total cash distributions made during the nine months ended September 30, 2013 and 2012 were as follows (in millions):

	Nine Months Ended September 30,	
	2013	2012
Common units	$ 82.3	$ 54.2
Preferred units (1)	—	14.4
General partner interest (including incentive distribution rights)	5.1	4.3
Total	$ 87.4	$ 72.9

(1) Excludes distributions paid through the issuance of paid-in-kind preferred units for the nine months ended September 30, 2013.

In order to reduce our interest costs, we do not borrow money to fund outstanding checks until they are presented to the bank. Fluctuations in drafts payable are caused by timing of disbursements, cash receipts and draws on our credit facility. We borrow money under our credit facility to fund checks as they are presented. As of September 30, 2013, we had approximately

$496.7 million of available borrowing capacity under our credit facility. Changes in drafts payable for thenine months ended September 30, 2013 and 2012 were as follows (in millions):

	Nine Months Ended September 30,	
	2013	2012
Increase in drafts payable	$ 1.3	$ 4.3

Working Capital. We had a working capital deficit of $28.0 million as of September 30, 2013. Changes in working capital may fluctuate significantly between periods even though our trade receivables and payables are typically collected and paid in 30 to 60 day pay cycles. A large volume of our revenues is collected and a large volume of our gas purchases is paid near each month end or the first few days of the following month. As such, receivable and payable balances at any month end may fluctuate significantly depending on the timing of these receipts and payments. During times of significant construction accounts payable balances also include construction related invoices, which negatively impact working capital until paid from long-term funds. In addition, although we strive to minimize the amount of time and volumes that our natural gas, NGLs and crude oil are kept in inventory, these working inventory balances may fluctuate significantly from period to period due to operational reasons and due to changes in natural gas, NGL and crude oil prices. Working capital also includes our mark to market derivative assets and liabilities associated with our commodity derivatives which may fluctuate significantly due to the changes in natural gas, NGL and crude oil prices.

Changes in Operations During 2012 and 2013. We have a gas gathering contract with a major producer in our North Texas assets with a primary term that expired August 31, 2012 that was modified to be on a month-to-month basis beginning September 1, 2012. Subsequently, the modified contract was extended for six months at a reduced gathering fee rate which did and will reduce our gross operating margin by approximately $1.2 million per quarter. The contract is currently rolling month to month in evergreen status (under the terms of the previously mentioned six month extension), and we are in the process of finalizing negotiations of a longer term agreement.

We own and operate a high-pressure pipeline and underground natural gas and NGL storage reservoirs and associated facilities near Bayou Corne, Louisiana. In August 2012, a large sinkhole formed in the vicinity of these pipelines and underground storage reservoirs. This sinkhole is situated west of our underground natural gas and NGL storage facility. The cause of the sinkhole is currently under investigation by Louisiana state and local officials. We took a section of our 36-inch-diameter natural gas pipeline located near the sinkhole out of service. Service to certain markets, primarily in the Mississippi River area, has been curtailed or interrupted, and we have worked with our customers to secure alternative natural gas supplies so that disruptions are minimized. We are currently in the initial phase of constructing the replacement pipeline in our rerouted location and anticipate services will resume during first half of 2014 due to permit delays.

We are assessing the potential for recovering our losses from responsible parties, and we are seeking recovery from our insurers. Our insurers, however, have denied our insurance claim for coverage and filed a declaratory judgment asking a court to determine that our insurance policy does not cover this damage. We have sued our insurers for breach of contract due to their refusal to pay our insurance claim for this damage. We have also sued Texas Brine, LLC, the operator of a failed cavern in the area, and its insurers seeking recovery for this damage. We cannot give assurance that we will be able to fully recover our losses through insurance recovery or claims against responsible parties.

Capital Requirements. During the nine months ended September 30, 2013, capital investments were $409.5 million, which were funded by internally generated cash flow, borrowings under our credit facility and equity offerings. Our remaining current growth capital spending projection for 2013 is approximately $160.0 million to $165.0 million related to identified growth projects, and our 2014 capital budget includes approximately $450.0 to $500.0 million of identified growth projects and capital interest. We expect to fund the growth capital expenditures from the proceeds of borrowing under our bank credit facility and from other debt and equity sources.

Off-Balance Sheet Arrangements. No off-balance sheet arrangements existed as of September 30, 2013.

Total Contractual Cash Obligations. A summary of contractual cash obligations as of September 30, 2013 is as follows (in millions):

	Payments Due by Period						
	Total	2013	2014	2015	2016	2017	Thereafter
Long-term debt obligations	$ 975.0	$ —	$ —	$ —	$ —	$ —	$ 975.0
Bank credit facility	76.0	—	—	—	76.0	—	—
Interest payable on fixed long-term debt obligations	448.9	8.9	82.1	82.1	82.2	82.2	111.4
Capital lease obligations	27.0	1.1	4.6	4.6	4.6	6.9	5.2
Operating lease obligations	56.9	1.8	10.1	10.2	8.2	5.1	21.5
Purchase obligations	13.7	13.7	—	—	—	—	—
Consulting agreement	3.8	0.3	3.5	—	—	—	—
Inactive easement commitment*	10.0	—	—	—	—	—	10.0
Uncertain tax position obligations	4.5	4.5	—	—	—	—	—
Total contractual obligations	$ 1,615.8	$ 30.3	$ 100.3	$ 96.9	$ 171.0	$ 94.2	$ 1,123.1

* Amounts related to inactive easements paid as utilized by the Partnership with balance due at end of 10 years if not utilized.

The above table does not include any physical or financial contract purchase commitments for natural gas due to the nature of both the price and volume components of such purchases, which vary on a daily or monthly basis.

The interest payable under the Partnership's credit facility is not reflected in the above table because such amounts depend on the outstanding balances and interest rates, which vary from time to time. However, given the same borrowing amount and rates in effect at September 30, 2013 the cash obligation for interest expense on the Partnership's credit facility would be approximately $2.7 million per year or approximately $0.7 million for the remainder of 2013.

Indebtedness

As of September 30, 2013 and December 31, 2012, long-term debt consisted of the following (in millions):

	September 30, 2013	December 31, 2012
Bank credit facility (due 2016), interest based on Prime and/or LIBOR plus an applicable margin, interest rate at September 30, 2013 and December 31, 2012 was 3.6% and 4.3%, respectively	$ 76.0	$ 71.0
Senior unsecured notes (due 2018), net of discount of $8.3 million and $9.7 million, respectively, which bear interest at the rate of 8.875%	716.7	715.3
Senior unsecured notes (due 2022), which bear interest at the rate of 7.125%	250.0	250.0
Debt classified as long-term	$ 1,042.7	$ 1,036.3

Credit Facility As of September 30, 2013, there were $62.3 million in outstanding letters of credit and $76.0 million in outstanding borrowings under the Partnership's bank credit facility, leaving approximately $496.7 million available for future borrowing based on the borrowing capacity of $635.0 million. As of September 30, 2013, based on our maximum permitted consolidated leverage ratio (as defined in the amended credit facility), we could borrow approximately $271.4 million of additional funds. The credit facility matures in May 2016. In January and August 2013, the Partnership amended the credit facility. See Note 3 to the condensed consolidated financial statements titled "Long-Term Debt" for further details.

Recent Accounting Pronouncements

In February 2013, the Financial Accounting Standards Board issued Accounting Standards Update 2013-02-Comprehensive Income (ASC 220), "*Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income*." This update requires that we report reclassifications out of accumulated other comprehensive income and their effect on net income by component or financial statement line. We have included the required disclosures in the notes to our financial statements for the nine months ended September 30, 2013.

We have reviewed all other recently issued accounting pronouncements that became effective during thenine months ended September 30, 2013 and have determined that none would have a material impact to our Unaudited Condensed Consolidated Financial Statements.

Disclosure Regarding Forward-Looking Statements

This Quarterly Report on Form 10-Q includes forward-looking statements. Statements included in this report which are not historical facts are forward-looking statements. These statements can be identified by the use of forward-looking terminology including "forecast," "may," "believe," "will," "expect," "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. Such statements reflect our current views with respect to future events based on what we believe are reasonable assumptions; however, such statements are subject to certain risks and uncertainties. In addition to specific uncertainties discussed elsewhere in this Form 10-Q, the risk factors set forth in Part I, "Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2012, and those set forth in Part II, "Item 1A. Risk Factors" of this report, if any, may affect our performance and results of operations. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual results may differ materially from those in the forward-looking statements. We disclaim any intention or obligation to update or review any forward-looking statements or information, whether as a result of new information, future events or otherwise.

Item 3. *Quantitative and Qualitative Disclosures about Market Risk*

Market risk is the risk of loss arising from adverse changes in market rates and prices. Our primary market risk is the risk related to changes in the prices of natural gas, NGLs and crude oil. In addition, we are exposed to the risk of changes in interest rates on our floating rate debt.

Comprehensive financial reform legislation was signed into law by the President on July 21, 2010. The legislation calls for the Commodities Futures Trading Commission ("CFTC") to regulate certain markets for derivative products, including over-the-counter ("OTC") derivatives. The CFTC has issued several new relevant regulations and other rulemakings are pending at the CFTC, the product of which would be rules that implement the mandates in the new legislation to cause significant portions of derivatives markets to clear through clearinghouses. The legislation and new regulations may also require counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The new legislation and any new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures and to generate sufficient cash flow to pay quarterly distributions at current levels or at all. Our revenues could be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material, adverse effect on us, our financial condition and our results of operations.

Commodity Price Risk

We are subject to significant risks due to fluctuations in commodity prices. Our exposure to these risks is primarily in the gas processing component of our business. We currently process gas under three main types of contractual arrangements:

1. *Processing margin contracts:* Under this type of contract, we pay the producer for the full amount of inlet gas to the plant, and we make a margin based on the difference between the value of liquids recovered from the processed natural gas as compared to the value of the natural gas volumes lost ("shrink") and the cost of fuel used in processing. The shrink and fuel losses are referred to as plant thermal reduction, or PTR. Our margins from these contracts are high during periods of high liquids prices relative to natural gas prices and can be negative during periods of high natural gas prices relative to liquids prices. However, we mitigate our risk of processing natural gas when margins are negative primarily through our ability to bypass processing when it is not profitable for us or by

contracts that revert to a minimum fee for processing if the natural gas must be processed to meet pipeline quality specifications.

2. *Percent of liquids ("POL") contracts:* Under these contracts, we receive a fee in the form of a percentage of the liquids recovered, and the producer bears all the cost of the natural gas shrink. Therefore, our margins from these contracts are greater during periods of high liquids prices. Our margins from processing cannot become negative under percent of liquids contracts, but do decline during periods of low NGL prices.

3. *Fee based contracts:* Under these contracts we have no commodity price exposure and are paid a fixed fee per unit of volume that is processed.

Gas processing margins by contract types and gathering, transportation and crude handling margins as a percent of total gross operating margin for the comparative year-to-date periods are as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Gathering, transportation and crude handling margin	62.2%	70.0%	61.6%	63.6%
Gas processing margins:				
Processing margin	4.7%	4.9%	4.5%	11.2%
Percent of liquids	8.6%	6.4%	8.9%	8.1%
Fee based	24.5%	18.7%	25.0%	17.1%
Total gas processing	37.8%	30.0%	38.4%	36.4%
Total	100.0%	100.0%	100.0%	100.0%

Our primary commodity risk management objective is to reduce volatility in our cash flows. We maintain a risk management committee, including members of senior management, which oversees all hedging activity. We enter into hedges for natural gas and NGLs using over-the-counter derivative financial instruments with only certain well-capitalized counterparties which have been approved by our risk management committee.

We have hedged our exposure to declines in prices for NGL volumes produced for our account. We hedge our exposure based on volumes we consider hedgeable (volumes committed under contracts that are long term in nature) versus total volumes that include volumes that may fluctuate due to contractual terms, such as contracts with month to month processing options.

We have hedges in place at September 30, 2013 covering a portion of the liquids volumes we expect to receive under POL contracts. The hedges were done via swaps and are set forth in the following tables. The relevant payment index price is the monthly average of the daily closing price for deliveries of commodities into Mont Belvieu, Texas as reported by the Oil Price Information Service (OPIS).

Period	Underlying	Notional Volume		We Pay	We Receive *	Fair Value Asset/(Liability) (In thousands)	
October 2013 - December 2013	Ethane	53	(MBbls)	Index	$0.3422/gal	$	199
October 2013 - December 2013	Propane	35	(MBbls)	Index	$1.0720/gal		7
October 2013 - December 2013	Iso Butane	7	(MBbls)	Index	$1.7135/gal		86
October 2013 - December 2013	Normal Butane	13	(MBbls)	Index	$1.6055/gal		110
October 2013 - December 2013	Natural Gasoline	13	(MBbls)	Index	$2.1446/gal		41
						$	443

*weighted average

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Period	Underlying	Notional Volume		We Pay	We Receive *	Fair Value Asset/(Liability) (In thousands)	
January 2014 - December 2014	Ethane	32	(MBbls)	Index	$0.2540/gal	$	(11)
January 2014 - December 2014	Propane	71	(MBbls)	Index	$0.9654/gal		(98)
January 2014 - December 2014	Normal Butane	18	(MBbls)	Index	$1.2415gal		(43)
January 2014 - December 2014	Natural Gasoline	12	(MBbls)	Index	$1.9560/gal		(28)
						$	(180)

*weighted average

We have hedged 80.1% of our total volumes at risk through December 2013 and hedged20.7% of our total volumes at risk for 2014 relating to our POL contracts.

We have hedges in place at September 30, 2013 covering the fractionation spread risk related to our processing margin contracts as set forth in the following tables:

Period	Underlying	Notional Volume		We Pay	We Receive *	Fair Value Asset/(Liability) (In thousands)	
October 2013 - December 2013	Ethane	7	(MBbls)	Index	$0.2825/gal	$	9
October 2013 - December 2013	Propane	18	(MBbls)	Index	$1.2222/gal		117
October 2013 - December 2013	Normal Butane	15	(MBbls)	Index	$1.6653/gal		164
October 2013 - December 2013	Natural Gasoline	8	(MBbls)	Index	$2.2168/gal		51
October 2013 - December 2013	Natural Gas	2,348	(MMBtu/d)	$3.82806/MMBtu*	Index		(46)
						$	295

*weighted average

Period	Underlying	Notional Volume		We Pay	We Receive *	Fair Value Asset/(Liability) (In thousands)	
January 2014 - December 2014	Ethane	5	(MBbls)	Index	$0.2800/gal	$	4
January 2014 - December 2014	Propane	21	(MBbls)	Index	$0.9545/gal		(49)
January 2014 - December 2014	Normal Butane	12	(MBbls)	Index	$1.2587/gal		(24)
January 2014 - December 2014	Natural Gasoline	7	(MBbls)	Index	$1.9642/gal		(16)
January 2014 - December 2014	Natural Gas	755	(MMBtu/d)	$4.19828/MMBtu*	Index		(79)
						$	(164)

*weighted average

We have hedged 17.9% of our total liquids volumes relating to our fractionation spread risk and21.5% of the related total PTR volumes through December 2013. We have also hedged 4.3% of our total liquids volumes at risk and5.3% of the related total PTR volumes through December 2014.

We are subject to price risk to a lesser extent for fluctuations in natural gas prices with respect to a portion of our gathering and transport services. Approximately 3.4% of the natural gas we market is purchased at a percentage of the relevant natural gas index price, as opposed to a fixed discount to that price.

Another price risk we face is the risk of mismatching volumes of gas bought or sold on a monthly price versus volumes bought or sold on a daily price. We enter each month with a balanced book of natural gas bought and sold on the same basis. However, it is normal to experience fluctuations in the volumes of natural gas bought or sold under either basis, which leaves us with short or long positions that must be covered. We use financial swaps to mitigate the exposure at the time it is created to maintain a balanced position.

The use of financial instruments may expose us to the risk of financial loss in certain circumstances, including instances when (1) sales volumes are less than expected requiring market purchases to meet commitments or (2) our counterparties fail to purchase the contracted quantities of natural gas or otherwise fail to perform. To the extent that we engage in hedging activities we may be prevented from realizing the benefits of favorable price changes in the physical market. However, we are similarly insulated against unfavorable changes in such prices.

As of September 30, 2013, outstanding natural gas swap agreements, NGL swap agreements, swing swap agreements, storage swap agreements and other derivative instruments were a net fair value asset of $0.5 million. The aggregate effect of a hypothetical 10% increase in gas and NGL prices would result in a decrease of approximately $1.5 million in the net fair value of these contracts as of September 30, 2013 to a net fair value liability of approximately $1.0 million.

Interest Rate Risk

We are exposed to interest rate risk on our variable rate bank credit facility. At September 30, 2013, we had $76.0 million in outstanding borrowings under this facility. A 1% increase or decrease in interest rates would change our annual interest expense by approximately $0.8 million for the year.

At September 30, 2013, we had fixed rate debt obligations of $716.7 million and $250.0 million, consisting of our senior unsecured notes with an interest rate of 8.875% and 7.125%, respectively. The fair value of the fixed rate obligations for the 2018 Notes and 2022 Notes was approximately $770.3 million and $256.3 million, respectively, as of September 30, 2013. We estimate that a 1% decrease or increase in interest rates would increase or decrease the fair value of the 2018 Notes and the 2022 Notes by $8.7 million and $13.2 million, respectively.

Item 4. ***Controls and Procedures***

(a) Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer of Crosstex Energy GP, LLC, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report pursuant to Exchange Act Rules 13a-15 and 15d-15. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of the period covered by this report (September 30, 2013), our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed by us in the reports we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time period specified in the applicable rules and forms, and that such information is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosure.

(b) Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting that occurred in the three months ended September 30, 2013 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II—OTHER INFORMATION

Item 1. ***Legal Proceedings***

We are involved in various litigation and administrative proceedings arising in the normal course of business. In the opinion of management, any liabilities that may result from these claims would not individually or in the aggregate have a material adverse effect on our financial position or results of operations.

For a discussion of certain litigation and similar proceedings, please refer to Note 9, “Commitments and Contingencies,” of the Notes to Condensed Consolidated Financial Statements, which is incorporated by reference herein.

Item 1A. ***Risk Factors***

Information about risk factors does not differ materially from that set forth in Part I, Item 1A of our Annual Report on Form 10-K for the fiscal year ended December 31, 2012 other than as supplemented by our Form 10-Q for the quarterly period ended March 31, 2013 in response to Part II, Item 1A. of such Form 10-Q and as listed below.

We cannot assure you that we will complete the Contribution, or if completed, that such transaction will be beneficial to us.

We cannot assure you that we will complete the Contribution, or if completed, that such transaction would achieve the desired benefits. The Contribution would involve numerous risks, including the failure to realize expected profitability or growth and an increase in collateral demands by our counterparties. Additionally, the failure to assimilate the Midstream Group Entities’ assets into our existing assets would adversely affect our financial condition and results of operations. We will also be exposed to risks that are commonly associated with any acquisition, such as unanticipated liabilities and costs, some of which may be material, and diversion of management’s attention. Moreover, the Midstream Group Entities’ operations are subject to similar stringent environmental laws and regulations relating to releases of pollutants into the environment and environmental protection as are our existing pipelines and facilities, and thus our operation of those new assets would cause us to incur increased costs to maintain compliance with such laws and regulations.

If we consummate the Contribution and if any of these risks or unanticipated liabilities or costs were to materialize, any desired benefits of the Contribution may not be fully realized, if at all, and our future financial performance and results of operations could be negatively impacted. Further, the failure to complete the Contribution could negatively impact the market price of our common units and our future business and financial results, and we may experience negative reactions from the financial markets and from our customers and employees.

If we complete the Contribution, we will expand our operations into new geographic areas.

The Contribution would, if ultimately consummated, significantly increase the size of our business and diversify the geographic areas in which we operate. Midstream Holdings operates its business in geographic regions in which we do not currently operate, including the Cana and Arkoma Woodford Shales in Oklahoma. In order to operate effectively in these new regions, we will need to understand the local market and regulatory environment and identify and retain certain employees from Devon who are familiar with these markets. If we are not successful in retaining these employees or operating in these new geographic areas, we may not be able to compete effectively in the new markets or fully realize the expected benefits of the Contribution.

Upon consummation of the Contribution, a significant portion of our operations will be located in the Barnett Shale, making us vulnerable to risks associated with having revenue-producing operations concentrated in a limited number of geographic areas.

Following the Contribution, our revenue-producing operations will be geographically concentrated in the Barnett Shale, causing us to be disproportionally exposed to risks associated with regional factors. The concentration of our operations in these regions also increases exposure to unexpected events that may occur in these regions such as natural disasters or labor difficulties. Any one of these events has the potential to cause a relatively significant impact to our operations and growth plans, decrease cash flows, increase operating and capital costs and prevent development within originally anticipated time frames. Any of these risks could have a material adverse effect on our financial condition and results of operations.

Following the Contribution, we will be dependent on Devon for substantially all of the natural gas that the Midstream Group Entities gather, process and transport, and a material decline in the volumes of natural gas that the Midstream Group Entities gather, process and transport for Devon would have a material adverse impact on our operating results and cash available for distribution.

The Midstream Group Entities rely on Devon for substantially all of their natural gas supply and do not expect to materially increase volumes from third-party producers in the near term. For the foreseeable future, we expect the profitability of the budsiness of the Midstream Group Entities to remain substantially dependent on the volume of natural gas that Devon provides under commercial agreements to be entered into in connection with the closing of the Contribution. Upon the expiration or termination of these agreements, or in the event that the volume of natural gas purchased under these commercial agreements is reduced, we would be adversely affected unless we were able to make comparably profitable arrangements with other customers.

Pending the completion of the Contribution, our business and operations could be materially adversely affected.

Under the terms of the Contribution Agreement, we are subject to certain restrictions on the conduct of our business prior to completing the transactions which may adversely affect our ability to execute certain of our business strategies, including our ability in certain cases to enter into contracts or incur capital expenditures to grow our business. Such limitations could negatively affect our business and operations prior to the completion of the Contribution. Furthermore, matters relating to the Contribution may require substantial commitments of time and resources by management, which could otherwise have been devoted to other opportunities that may have been beneficial to us.

We will incur substantial transaction-related costs in connection with the Contribution.

We expect to incur a number of non-recurring transaction-related costs associated with completing the Contribution, combining the operations of the Midstream Group Entities with our business and achieving desired synergies. These fees and costs will be substantial. There can be no assurance that the elimination of certain duplicative costs, as well as the realization of other efficiencies related to the integration of the two businesses, will offset the incremental transaction-related costs over time. Thus, any net benefit may not be achieved in the near term, or at all.

The consummation of the Contribution and the Mergers would constitute a change of control of us.

The Partnership's unitholders will have a reduced ownership and voting interest after the Contribution and will exercise less influence over management. Further, following the consummation of the Mergers, our General Partner will be an indirect wholly-owned subsidiary of New Public Rangers, a new public holding company that will be controlled by Devon. CEI stockholders currently have the right to vote in the election of the CEI board of directors and other matters affecting CEI. When the merger occurs, each CEI shareholder that receives New Public Rangers common units will become a unitholder of New Public Rangers with a percentage ownership of the combined organization that is much smaller than such stockholder's percentage ownership of CEI. New Public Rangers unitholders are not entitled to elect the directors of New Public Rangers' general partner and have only limited voting rights on matters affecting New Public Rangers' business and, therefore, limited ability to influence management's decisions regarding our business. Because of its control of New Public Rangers and our General Partner, as well as due to its significant ownership of us following the Contribution, Devon will have the ability to influence our management, policies and business in a manner that may differ from our past practice.

The closing of the Contribution and the Mergers would trigger an event of default under our credit facility and a mandatory repurchase offer under the indenture governing our 2018 Notes and, in certain circumstances, our 2022 Notes.

The closing of the Contribution and the Mergers will trigger an event of default under our credit facility and a mandatory repurchase offer under the indenture governing our 2018 Notes. Completion of the Contribution and the Mergers also could trigger a mandatory repurchase offer under the indenture governing our 2022 Notes if, within 90 days of the consummation of the transactions, we experience a rating downgrade of the 2022 Notes by either Moody's or S&P. If we are unable to negotiate an amendment or waiver of the applicable provisions in our credit facility or if we are unable to fund a repurchase of our 2018 Notes or, if necessary, our 2022 Notes, the counterparties may exercise their rights and remedies under the agreements. Even if we are able to negotiate an amendment or waiver, the lenders under our credit facility may require a fee for such waiver or seek to renegotiate the credit agreement on less favorable terms. Further, during the pendency of the proposed transactions, a decrease in Devon's perceived creditworthiness may have an adverse effect on our perceived creditworthiness, possibly resulting in a downgrade of credit ratings, tightening of credit under our existing credit facility or increasing our borrowing costs.

Item 6. ***Exhibits***

The exhibits filed as part of this report are as follows (exhibits incorporated by reference are set forth with the name of the registrant, the type of report and registration number or last date of the period for which it was filed, and the exhibit number in such filing):

Number		Description
2.1**	—	Stock Purchase and Sale Agreement, dated as of May 7, 2012, by and among Energy Equity Partners, L.P., the Individual Owners (as defined therein), Clearfield Energy, Inc., Clearfield Holdings, Inc., West Virginia Oil Gathering Corporation, Appalachian Oil Purchasers, Inc., Kentucky Oil Gathering Corporation, Ohio Oil Gathering Corporation II, Ohio Oil Gathering Corporation III, OOGC Disposal Company I, M&B Gas Services, Inc., Clearfield Ohio Holdings, Inc., Pike Natural Gas Company, Eastern Natural Gas Company, Southeastern Natural Gas Company and Crosstex Energy Services, L.P. (incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K dated May 7, 2012, filed with the Commission on May 8, 2012).
2.2**	—	Contribution Agreement, dated as of October 21, 2013, by and among Devon Energy Corporation, Devon Gas Corporation, Devon Gas Services, L.P., Southwestern Gas Pipeline, Inc., Crosstex Energy, L.P. and Crosstex Energy Services, L.P. (incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K dated October 21, 2013, filed with the Commission on October 22, 2013).
3.1	—	Certificate of Limited Partnership of Crosstex Energy, L.P. (incorporated by reference to Exhibit 3.1 to our Registration Statement on Form S-1, file No. 333-97779).
3.2	—	Certificate of Amendment to the Certificate of Limited Partnership of Crosstex Energy, L.P. (incorporated by reference to Exhibit 3.2 to our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2012).
3.3	—	Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of March 23, 2007 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated March 23, 2007, filed with the Commission on March 27, 2007).
3.4	—	Amendment No. 1 to Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P. dated December 20, 2007 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated December 20, 2007, filed with the Commission on December 21, 2007).
3.5	—	Amendment No. 2 to Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P. (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated March 27, 2008, filed with the Commission on March 28, 2008).
3.6	—	Amendment No. 3 to Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of January 19, 2010 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated January 19, 2010, filed with the Commission on January 22, 2010).
3.7	—	Amendment No. 4 to Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of September 13, 2012 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated September 13, 2012, filed with the Commission on September 14, 2012).
3.8	—	Certificate of Formation of Crosstex Energy GP, LLC (incorporated by reference to Exhibit 3.7 to our Registration Statement on Form S-1, file No. 333-97779).
3.9	—	Amended and Restated Limited Liability Company Agreement of Crosstex Energy GP, LLC, dated as of December 17, 2002 (incorporated by reference to Exhibit 3.8 to our Registration Statement on Form S-1, file No. 333-97779).
3.10	—	Amendment No. 1 to Amended and Restated Limited Liability Company Agreement of Crosstex Energy GP, LLC, dated as of January 19, 2010 (incorporated by reference to Exhibit 3.2 to our Current Report on Form 8-K dated January 19, 2010, filed with the Commission on January 22, 2010).
10.1	—	Eighth Amendment to Amended and Restated Credit Agreement, dated as of August 28, 2013, by and among Crosstex Energy, L.P., Bank of America, N.A., as Administrative Agent and L/C Issuer, and the other lenders party thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated August 28, 2013, filed with the Commission on August 30, 2013).
31.1*	—	Certification of the Principal Executive Officer.
31.2*	—	Certification of the Principal Financial Officer.
32.1*	—	Certification of the Principal Executive Officer and Principal Financial Officer pursuant to 18 U.S.C. Section 1350.
101*	—	The following financial information from Crosstex Energy, L.P.'s Quarterly Report on Form 10-Q for the quarter ended September 30, 2013, formatted in XBRL (eXtensible Business Reporting Language): (i) Condensed Consolidated Balance Sheets as of September 30, 2013 and December 31, 2012, (ii) Condensed Consolidated Statements of Operations for the three and nine months ended September 30, 2013 and 2012, (iii) Consolidated Statements of Comprehensive Income for the three and nine months ended September 30, 2013 and 2012, (iv) Consolidated Statements of Changes in Partners' Equity for the nine months ended September 30, 2013, (v) Consolidated Statements of Cash Flows for the nine months ended September 30, 2013 and 2012, and (vi) the Notes to Condensed Consolidated Financial Statements.

* Filed herewith.

** Pursuant to Item 601(b)(2) of Regulation S-K, the Registrant agrees to furnish supplementally a copy of any omitted exhibit or schedule to the SEC upon request.

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.

CROSSTEX ENERGY, L.P.

By: Crosstex Energy GP, LLC,
its general partner

By: /s/ MICHAEL J. GARBERDING
Michael J. Garberding
Executive Vice President and Chief Financial Officer

November 8, 2013

Exhibit 31.1

CERTIFICATIONS

I, Barry E. Davis, President and Chief Executive Officer of Crosstex Energy GP, LLC, the general partner of the registrant, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Crosstex Energy, L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ BARRY E. DAVIS

BARRY E. DAVIS
President and Chief Executive Officer
(principal executive officer)

Date: November 8, 2013

Exhibit 31.2

CERTIFICATIONS

I, Michael J. Garberding, Executive Vice President and Chief Financial Officer of Crosstex Energy GP, LLC, the general partner of the registrant, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Crosstex Energy, L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ MICHAEL J. GARBERDING

MICHAEL J. GARBERDING
Executive Vice President and Chief Financial Officer
(principal financial and accounting officer)

Date: November 8, 2013

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Crosstex Energy, L.P. (the "Registrant") on Form 10-Q for the quarter ended September 30, 2013 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each of the undersigned, Barry E. Davis, Chief Executive Officer of Crosstex Energy GP, LLC, and Michael J. Garberding, Chief Financial Officer of Crosstex Energy GP, LLC, certifies, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Registrant.

/s/ BARRY E. DAVIS
Barry E. Davis
Chief Executive Officer

November 8, 2013

/s/ MICHAEL J. GARBERDING
Michael J. Garberding
Chief Financial Officer

November 8, 2013

A signed original of this written statement required by Section 906 has been provided to the Registrant and will be retained by the Registrant and furnished to the Securities and Exchange Commission or its staff upon request. The foregoing certification is being furnished to the Securities and Exchange Commission as an exhibit to the Report.