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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 June 30, 2012

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 (State of organization)	**16-1616605** (I.R.S. Employer Identification No.)
2501 CEDAR SPRINGS **DALLAS, TEXAS** (Address of principal executive offices)	**75201** (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 July 27, 2012, the Registrant had 61,022,866 common units outstanding.

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CROSSTEX ENERGY, L.P.

Condensed Consolidated Balance Sheets

	June 30, 2012 (Unaudited)	December 31, 2011
	(In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 4,959	$ 24,143
Restricted cash (1)	245,100	—
Accounts receivable:		
Trade, net of allowance for bad debt of $362 and $405, respectively	37,258	22,680
Accrued revenue and other	103,622	143,115
Fair value of derivative assets	6,680	2,867
Natural gas and natural gas liquids, prepaid expenses and other	22,860	9,951
Total current assets	420,479	202,756
Property and equipment, net of accumulated depreciation of $445,795 and $406,273, respectively	1,285,968	1,241,901
Fair value of derivative assets	1,604	—
Intangible assets, net of accumulated amortization of $224,729 and $199,248, respectively	425,981	451,462
Investment in limited liability company	87,250	35,000
Other assets, net	22,953	24,212
Total assets	$ 2,244,235	$ 1,955,331
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable, drafts payable and other	$ 27,887	$ 22,550
Accrued gas purchases	76,787	106,232
Fair value of derivative liabilities	2,839	5,587
Current portion of long-term debt (1)	250,000	—
Other current liabilities	45,162	66,065
Accrued interest	27,036	24,918
Total current liabilities	429,711	225,352
Long-term debt	762,357	798,409
Other long-term liabilities	22,383	23,919
Deferred tax liability	6,941	7,192
Fair value of derivative liabilities	7	—
Commitments and contingencies	—	—
Partners' equity	1,022,836	900,459
Total liabilities and partners' equity	$ 2,244,235	$ 1,955,331

(1) See Footnote 2 - 2022 Notes for additional information.

See accompanying notes to condensed consolidated financial statements.

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CROSSTEX ENERGY, L.P.

Condensed Consolidated Statements of Operations

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
	(Unaudited) (In thousands, except per unit amounts)			
Revenues	$ 351,194	$ 525,735	$ 722,903	$ 1,015,505
Operating costs and expenses:				
Purchased gas and NGLs	260,890	429,177	532,846	829,111
Operating expenses	30,571	27,913	58,378	52,957
General and administrative	12,965	12,643	27,928	24,399
Gain on sale of property	(406)	(60)	(504)	(80)
(Gain) loss on derivatives	(4,905)	1,536	(2,736)	4,957
Depreciation and amortization	32,870	31,636	65,048	61,289
Total operating costs and expenses	331,985	502,845	680,960	972,633
Operating income	19,209	22,890	41,943	42,872
Other income (expense):				
Interest expense, net of interest income	(21,320)	(20,676)	(40,703)	(40,444)
Other income (expenses)	11	(241)	25	(129)
Total other expense	(21,309)	(20,917)	(40,678)	(40,573)

Income (loss) before non-controlling interest and income taxes	(2,100)	1,973	1,265	2,299
Income tax provision	(411)	(358)	(835)	(611)
Net income (loss)	(2,511)	1,615	430	1,688
Less: Net loss attributable to the non-controlling interest	(71)	(52)	(109)	(107)
Net income (loss) attributable to Crosstex Energy, L.P.	$ (2,440)	$ 1,667	$ 539	$ 1,795
Preferred interest in net income attributable to Crosstex Energy, L.P.	$ 4,853	$ 4,559	$ 9,706	$ 8,824
General partner interest in net income (loss)	$ (40)	$ (111)	$ (111)	$ (633)
Limited partners' interest in net loss attributable to Crosstex Energy, L.P.	$ (7,253)	$ (2,781)	$ (9,056)	$ (6,396)
Net loss attributable to Crosstex Energy, L.P. per limited partners' unit:				
Basic and diluted per common unit	$ (0.13)	$ (0.05)	$ (0.17)	$ (0.12)

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 June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(Unaudited) (In thousands)			
Net income (loss)	$ (2,511)	$ 1,615	$ 430	$ 1,688
Hedging (gains) losses reclassified to earnings	71	701	425	1,089
Adjustment in fair value of derivatives	1,796	(138)	1,757	(1,535)
Comprehensive income (loss)	(644)	2,178	2,612	1,242
Comprehensive loss attributable to non-controlling interest	71	52	109	107
Comprehensive income (loss) attributable to Crosstex Energy, L.P.	$ (573)	$ 2,230	$ 2,721	$ 1,349

See accompanying notes to condensed consolidated financial statements.

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CROSSTEX ENERGY, L.P.

Consolidated Statements of Changes in Partners' Equity
Six Months Ended June 30, 2012

	Common Units		Preferred Units		General Partner Interest		Accumulated Other Comprehensive Income (loss)	Non-Controlling Interest	Total
	$	Units	$	Units	$	Units			
	(Unaudited) (In thousands)								
Balance, December 31, 2011	$ 730,010	50,677	$ 147,770	14,706	$ 20,322	1,334	$ (503)	$ 2,860	$ 900,459
Issuance of common units	158,014	10,120	—	—	3,362	207	—	—	161,376
Proceeds from exercise of unit options	203	40	—	—	—	—	—	—	203
Conversion of restricted units for common units, net of units withheld for taxes	(980)	172	—	—	—	—	—	—	(980)
Capital contributions	—	—	—	—	87	4	—	—	87
Stock-based compensation	2,662	—	—	—	2,331	—	—	—	4,993
Distributions	(33,694)	—	(9,559)	—	(2,661)	—	—	—	(45,914)
Net income (loss)	(9,056)	—	9,706	—	(111)	—	—	(109)	430
Hedging gains or losses reclassified to earnings	—	—	—	—	—	—	425	—	425
Adjustment in fair value of derivatives	—	—	—	—	—	—	1,757	—	1,757
Balance, June 30, 2012	$ 847,159	61,009	$ 147,917	14,706	$ 23,330	1,545	$ 1,679	$ 2,751	$ 1,022,836

See accompanying notes to condensed consolidated financial statements.

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CROSSTEX ENERGY, L.P.

Consolidated Statements of Cash Flows

	Six Months Ended June 30,	
	2012	2011
	(Unaudited) (In thousands)	
Cash flows from operating activities:		
Net income	$ 430	$ 1,688
Adjustments to reconcile net income to net cash provided by operating activities:		

Depreciation and amortization	65,048	61,289
Gain on sale of property	(504)	(80)
Deferred tax benefit	(250)	(250)
Non-cash stock-based compensation	4,993	3,995
Non-cash portion of derivatives (gain) loss	(5,975)	828
Amortization of debt issue costs	1,321	4,065
Amortization of discount on notes	948	948
Equity in loss of limited liability company	—	236
Changes in assets and liabilities:		
Accounts receivable, accrued revenue and other	24,906	(10,638)
Natural gas and natural gas liquids, prepaid expenses and other	(8,971)	(5,403)
Accounts payable, accrued gas purchases and other accrued liabilities	(29,655)	8,478
Net cash provided by operating activities	52,291	65,156
Cash flows from investing activities:		
Additions to property and equipment	(90,046)	(49,643)
Proceeds from sale of property	632	107
Investment in limited liability company	(52,250)	(35,000)
Net cash used in investing activities	(141,664)	(84,536)
Cash flows from financing activities:		
Proceeds from borrowings	548,500	277,250
Payments on borrowings	(335,500)	(232,308)
Increase in restricted cash	(245,100)	—
Payments on capital lease obligations	(1,536)	(1,509)
Increase (decrease) in drafts payable	(5,985)	3,165
Debt refinancing costs	(4,962)	(3,792)
Conversion of restricted units, net of units withheld for taxes	(980)	(1,740)
Issuance of common units	158,014	—
Distribution to partners	(45,914)	(37,589)
Proceeds from exercise of unit options	203	392
Contributions from general partner	3,449	145
Net cash provided by financing activities	70,189	4,014
Net decrease in cash and cash equivalents	(19,184)	(15,366)
Cash and cash equivalents, beginning of period	24,143	17,697
Cash and cash equivalents, end of period	$ 4,959	$ 2,331
Cash paid for interest	$ 36,252	$ 35,936
Cash paid for income taxes	$ 784	$ 752

See accompanying notes to condensed consolidated financial statements.

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CROSSTEX ENERGY, L.P.

Notes to Condensed Consolidated Financial Statements

June 30, 2012
(Unaudited)

(1) General

Unless the context requires otherwise, references to "we," "us," "our" orthe "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, transmission, processing and marketing of natural gas, natural gas liquids, or NGLs, and providing terminal services for crude oil. The Partnership connects the wells of natural gas producers in the geographic areas of its gathering systems in order to gather for a fee or purchase the gas production, processes natural gas for the removal of NGLs, transports natural gas and NGLs and ultimately provides natural gas and NGLs to a variety of markets. The Partnership operates 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, the Partnership purchases natural gas and NGLs from producers not connected to its gathering systems for resale and markets natural gas and NGLs on behalf of producers for a fee. The Partnership recently added crude oil terminal facilities in south Louisiana to provide access for crude oil producers to the premium markets in this area.

Crosstex Energy GP, LLC 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 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, 2011.

The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America 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) Investment in Limited Liability Company

On June 22, 2011, the Partnership entered into a limited liability agreement with Howard Energy Partners ("HEP") for an initial capital contribution of $35.0 million in exchange for an individual ownership interest in HEP. In 2012, the Partnership made an additional capital contribution of $52.3 million to HEP related to HEP's acquisition of substantially all of Meritage Midstream Services' natural gas gathering assets in south Texas. HEP owns midstream assets and provides midstream and construction services to Eagle Ford Shale producers. The Partnership owns 30.6 percent of HEP and accounts for this investment under the equity method of accounting. This investment is reflected on the balance sheet as "Investment in limited liability company."

(c) Potential Changes in use of Sabine Plant during 2012

Currently, the Partnership's Sabine plant has a contract with a third-party to fractionate the raw-make NGLs produced by the Sabine plant. The primary term of the contract expired on June 30, 2012 and is currently renewed on a month-to-month basis. The Partnership will negotiate with this third-party to try to establish a long-term fractionation agreement. If this third-party ceases to fractionate the produced NGLs from the Sabine plant and the Partnership is unsuccessful in determining another alternative for our Sabine customers, the Partnership will cease operation of the Sabine plant. Although the Partnership does not have specific plans at this time to relocate the Sabine plant if it is idled, the Partnership may utilize it elsewhere in its operations. The net book value of the Sabine plant was $46.4 million (including $13.3 million of intangible assets attributable to customer relationships) as of June 30, 2012. If the plant is idled on a long-term basis, an impairment may be recorded to expense the non-recoverable costs associated with the plant's current location, which are estimated to be approximately $27.0 million based on the net book value as of June 30, 2012.

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(d) Clearfield Acquisition

On July 2, 2012, the Partnership, through a wholly-owned subsidiary, completed its previously announced acquisition of all of the issued and outstanding common stock of Clearfield Energy, Inc. and Clearfield Energy's wholly-owned subsidiaries (collectively, "Clearfield"). Clearfield is a well-established crude oil, condensate and water services company with operations in Ohio, Kentucky and West Virginia. Clearfield's business includes 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 water disposal wells.

The Partnership paid approximately $210.0 million in cash for the acquisition and the purchase was funded from restricted cash that resulted from the senior notes offering in May 2012. The assets associated with this acquisition will be included in a new reporting segment that will be referred to as Ohio River Valley. Pro-forma financial statements for the Clearfield acquisition are available on our amended Current Report on Form 8-K/A filed on August 1, 2012.

(2) Long-Term Debt

As of June 30, 2012 and December 31, 2011, long-term debt consisted of the following (in thousands):

		June 30, 2012		December 31, 2011
Bank credit facility (due 2016), interest based on Prime and/or LIBOR plus an applicable margin, interest rate at June 30, 2012 and December 31, 2011 was 3.33% and 2.9%, respectively	$	48,000	$	85,000
Senior unsecured notes (due 2018), net of discount of $10.6 million and $11.6 million, respectively, which bear interest at the rate of 8.875%		714,357		713,409
Senior unsecured notes (due 2022), which bear interest at the rate of 7.125%		250,000		—
		1,012,357		798,409
Less current portion		(250,000)		—
Debt classified as long-term	$	762,357	$	798,409

Credit Facility. As of June 30, 2012, there was $57.6 million in outstanding letters of credit and $48.0 million borrowed under the Partnership's bank credit facility, leaving approximately $529.4 million available for future borrowing based on the borrowing capacity of $635.0 million.

In January, 2012, the Partnership amended its credit facility. This amendment increased its borrowing capacity from $485.0 million to $635.0 million and amended certain terms under the facility to provide additional financial flexibility during the remaining four-year term of the facility.

In May 2012, the Partnership amended its credit facility. The amendment to the Partnership's credit facility, among other things, (i) increased 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) during the Clearfield acquisition period (as defined in the amended credit facility, being generally the four quarterly

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measurement periods after closing the Clearfield acquisition) from 5.0 to 1.0 to 5.5 to 1.0, and (ii) increased the maximum permitted consolidated leverage ratio during any other acquisition period (as defined in the amended credit facility, being generally the three quarterly measurement periods after closing certain material acquisitions) from 5.0 to 1.0 to 5.5 to 1.0.

The credit facility is guaranteed by substantially all of the Partnership's subsidiaries and is secured by first priority liens on substantially all of the Partnership's 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 the Partnership's equity interests in substantially all of its subsidiaries and its interest in HEP. The Partnership may prepay all loans under the amended credit facility at any time without premium or penalty (other than customary LIBOR breakage costs), subject to certain notice requirements.

All 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, 2011. The Partnership expects to be in compliance with all credit facility covenants for at least the next twelve months.

2022 Notes. On May 24, 2012, the Partnership issued $250.0 million in aggregate principal amount of 7.125% senior unsecured notes (the "2022 Notes") due on June 1, 2022 at an issue price of 100% of the principal amount to yield 7.125% to maturity. The interest payments are due semi-annually in arrears in June and December. The Partnership placed into escrow the net proceeds of $245.1 million from the offering of the 2022 Notes pending completion of the Clearfield acquisition. The net proceeds are classified as restricted cash as of June 30, 2012 and the 2022 Notes are classified as current debt as of June 30, 2012. Upon closing of the Clearfield acquisition on July 2, 2012, the 2022 Notes were reclassified as long term debt and the restricted cash was used to fund the Clearfield acquisition and for general partnership purposes, including capital expenditures for the Cajun-Sibon natural gas liquids pipeline expansion.

The Partnership may redeem up to 35% of the 2022 Notes at any time prior to June 1, 2015 with the cash proceeds from equity offerings at a redemption price of 107.125% of the principal amount of the 2022 Notes (plus accrued and unpaid interest to the redemption date).

Prior to June 1, 2017, the Partnership may redeem all or a part of the 2022 Notes at the redemption price equal to the sum of the principal amount thereof, plus a make-whole premium at the redemption date, plus accrued and unpaid interest to the redemption date.

On or after June 1, 2017, the Partnership may redeem all or a part of the 2022 Notes at redemption prices (expressed as percentages of principal amount) equal to 103.563% for the twelve-month period beginning on June 1, 2017, 102.375% for the twelve-month period beginning on June 1, 2018, 101.188% for the twelve-month period beginning on June 1, 2019 and 100.000% for the twelve-month period beginning on June 1, 2020 and at any time thereafter, plus accrued and unpaid interest, if any, to the applicable redemption date on the 2022 Notes.

Under the terms of the indenture governing the 2022 Notes agreement, repurchase offer obligations would be triggered by a change of control combined with a ratings decline on the notes. All other material terms of the senior unsecured notes are described in footnote 4 to the consolidated financial statements in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2011.

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), CDC (the Partnership's joint venture in Denton County, Texas which is not 100% owned by the Partnership) 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. 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 six months ended June 30, 2012 and 2011 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 six months ended June 30, 2012 and 2011 as these amounts are not considered material.

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Condensed Consolidating Balance Sheets
June 30, 2012

	Guarantors	Non-Guarantors	Elimination	Consolidated
		(In thousands)		
ASSETS				
Total current assets	$ 405,623	$ 14,856	$ —	$ 420,479
Property, plant and equipment, net	1,076,248	209,720	—	1,285,968
Total other assets	537,788	—	—	537,788
Total assets	$ 2,019,659	$ 224,576	$ —	$ 2,244,235
LIABILITIES & PARTNERS' CAPITAL				
Total current liabilities	$ 424,239	$ 5,472	$ —	$ 429,711
Long-term debt	762,357	—	—	762,357
Other long-term liabilities	29,331	—	—	29,331
Partners' capital	803,732	219,104	—	1,022,836
Total liabilities & partners' capital	$ 2,019,659	$ 224,576	$ —	$ 2,244,235

December 31, 2011

	Guarantors	Non-Guarantors	Elimination	Consolidated
		(In thousands)		
ASSETS				
Total current assets	$ 189,410	$ 13,346	$ —	$ 202,756
Property, plant and equipment, net	1,026,537	215,364	—	1,241,901
Total other assets	510,671	3	—	510,674
Total assets	$ 1,726,618	$ 228,713	$ —	$ 1,955,331
LIABILITIES & PARTNERS' CAPITAL				
Total current liabilities	$ 220,811	$ 4,541	$ —	$ 225,352
Long-term debt	798,409	—	—	798,409
Other long-term liabilities	31,111	—	—	31,111
Partners' capital	676,287	224,172	—	900,459
Total liabilities & partners' capital	$ 1,726,618	$ 228,713	$ —	$ 1,955,331

Condensed Consolidating Statements of Operations
For the Three Months Ended June 30, 2012

	Guarantors	Non-Guarantors	Elimination	Consolidated
		(In thousands)		
Total revenues	$ 336,828	$ 22,200	$ (7,834)	$ 351,194

	Guarantors	Non-Guarantors	Elimination	Consolidated
Total operating costs and expenses	(330,072)	(9,747)	7,834	(331,985)
Operating income	6,756	12,453	—	19,209
Interest expense, net	(21,320)	—	—	(21,320)
Other income	11	—	—	11
Income (loss) before non-controlling interest and income taxes	(14,553)	12,453	—	(2,100)
Income tax provision	(408)	(3)	—	(411)
Net loss attributable to non-controlling interest	—	71	—	71
Net income (loss) attributable to Crosstex Energy, L.P.	$ (14,961)	$ 12,521	$ —	$ (2,440)

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CROSSTEX ENERGY, L.P.

Notes to Condensed Consolidated Financial Statements

For the Three Months Ended June 30, 2011

	Guarantors	Non-Guarantors	Elimination	Consolidated
		(In thousands)		
Total revenues	$ 511,104	$ 21,957	$ (7,326)	$ 525,735
Total operating costs and expenses	(499,421)	(10,750)	7,326	(502,845)
Operating income	11,683	11,207	—	22,890
Interest expense, net	(20,676)	—	—	(20,676)
Other expense	(241)	—	—	(241)
(Loss) income before non-controlling interest and income taxes	(9,234)	11,207	—	1,973
Income tax provision	(354)	(4)	—	(358)
Net income attributable to non-controlling interest	—	52	—	52
Net (loss) income attributable to Crosstex Energy, L.P.	$ (9,588)	$ 11,255	$ —	$ 1,667

For the Six Months Ended June 30, 2012

	Guarantors	Non-Guarantors	Elimination	Consolidated
		(In thousands)		
Total revenues	$ 693,981	$ 44,477	$ (15,555)	$ 722,903
Total operating costs and expenses	(677,659)	(18,856)	15,555	(680,960)
Operating income	16,322	25,621	—	41,943
Interest expense, net	(40,646)	(57)	—	(40,703)
Other income	25	—	—	25
Income (loss) before non-controlling interest and income taxes	(24,299)	25,564	—	1,265
Income tax provision	(828)	(7)	—	(835)
Net loss attributable to non-controlling interest	—	109	—	109
Net income (loss) attributable to Crosstex Energy, L.P.	$ (25,127)	$ 25,666	$ —	$ 539

For the Six Months Ended June 30, 2011

	Guarantors	Non-Guarantors	Elimination	Consolidated
		(in thousands)		
Total revenues	$ 986,044	$ 43,860	$ (14,399)	$ 1,015,505
Total operating costs and expenses	(967,573)	(19,459)	14,399	(972,633)
Operating income	18,471	24,401	—	42,872
Interest expense, net	(40,444)	—	—	(40,444)
Other expense	(129)	—	—	(129)
(Loss) income before non-controlling interest and income taxes	(22,102)	24,401	—	2,299
Income tax provision	(603)	(8)	—	(611)
Net loss attributable to non-controlling interest	—	107	—	107
Net (loss) income attributable to Crosstex Energy, L.P.	$ (22,705)	$ 24,500	$ —	$ 1,795

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CROSSTEX ENERGY, L.P.

Notes to Condensed Consolidated Financial Statements

Condensed Consolidating Statements of Cash Flow
For the Six Months Ended June 30, 2012

	Guarantors	Non-Guarantors	Elimination	Consolidated
		(In thousands)		
Net cash flows provided by operating activities	$ 20,468	$ 31,823	$ —	$ 52,291
Net cash flows used in investing activities	$ (141,037)	$ (627)	$ —	$ (141,664)
Net cash flows provided by (used in) financing activities	$ 70,189	$ (30,626)	$ 30,626	$ 70,189

For the Six Months Ended June 30, 2011

	Guarantors	Non-Guarantors	Elimination	Consolidated
		(In thousands)		
Net cash flows provided by operating activities	$ 33,900	$ 31,256	$ —	$ 65,156
Net cash flows used in investing activities	$ (82,176)	$ (2,360)	$ —	$ (84,536)
Net cash flows provided by (used in) financing activities	$ 4,014	$ (28,217)	$ 28,217	$ 4,014

(3) Other Long-term Liabilities

Prior to January 1, 2011, the Partnership entered into 9 and 10-year capital leases for certain equipment. Assets under capital leases as of June 30, 2012 are summarized as follows (in thousands):

Compressor equipment	$ 37,199
Less: Accumulated amortization	(12,087)
Net assets under capital leases	$ 25,112

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 June 30, 2012 (in thousands):

2012	$ 2,291
2013 through 2016 ($4,582 annually)	18,328
Thereafter	12,100
Less: Interest	(5,888)
Net minimum lease payments under capital lease	26,831
Less: Current portion of net minimum lease payments	(4,448)
Long-term portion of net minimum lease payments	$ 22,383

(4) Partners' Capital

(a) Issuance of Common Units

On May 15, 2012, we issued 10,200,000 common units representing limited partner interests in the Partnership at a public offering price of $16.28 per unit for net proceeds of $158.0 million. In addition, Crosstex Energy GP, LLC made a general partner contribution of $3.4 million in connection with the issuance to maintain its 2% general partner interest. The net proceeds from the common units offering were used for general partnership purposes.

(b) Cash Distributions

Unless restricted by the terms of the Partnership's credit facility and/or the indentures governing our 2022 Notes and our 8 7/8% senior unsecured notes due 2018 ("2018 Notes" and, together with the 2022 Notes, "all senior unsecured notes"), the Partnership must make distributions of 100% of available cash, as defined in the partnership agreement, within 45 days following the end of each quarter.

The Partnership's first quarter 2012 distribution on its common and preferred units of $0.33 per unit was paid on May 15, 2012. The Partnership declared its second quarter 2012 distribution on its common and preferred units of $0.33 per unit to be paid on August 14, 2012.

(c) Earnings per Unit and Dilution Computations

The Partnership had common units and preferred units outstanding during the three and six months ended June 30, 2012 and June 30, 2011.

The preferred units are entitled to a quarterly distribution 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.

As required under FASB 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 units for the periods presented (in thousands except per unit amounts):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Limited partners' interest in net loss	$ (7,253)	$ (2,781)	$ (9,056)	$ (6,396)
Distributed earnings allocated to:				
Common units (1)(2)	$ 18,021	$ 15,691	$ 34,804	$ 30,316
Unvested restricted units (1)(2)	359	286	698	585
Total distributed earnings	$ 18,380	$ 15,977	$ 35,502	$ 30,901
Undistributed loss allocated to:				
Common units	$ (25,148)	$ (18,374)	$ (43,699)	$ (36,605)
Unvested restricted units	(485)	(384)	(859)	(692)
Total undistributed loss	$ (25,633)	$ (18,758)	$ (44,558)	$ (37,297)
Net loss allocated to:				
Common units	$ (7,127)	$ (2,683)	$ (8,895)	$ (6,289)
Unvested restricted units	(126)	(98)	(161)	(107)
Total limited partners' interest in net loss	$ (7,253)	$ (2,781)	$ (9,056)	$ (6,396)
Basic and diluted net loss per unit:				
Basic and diluted common unit	$ (0.13)	$ (0.05)	$ (0.17)	$ (0.12)

(1) Three months ended June 30, 2012 represents a declared distribution of $0.33 per unit payable on August 14, 2012. Six months ended June 30, 2012 represents

distributions paid of $0.33 per unit and distributions declared of $0.33 payable August 14, 2012.

(2) Three months ended June 30, 2011 represents a declared distribution of $0.31 per unit paid on August 12, 2011. Six months ended June 30, 2011 represents distributions paid of $0.29 per unit and distributions declared of $0.31 paid August 12, 2011.

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The following are the unit amounts used to compute the basic and diluted earnings per limited partner unit for the three and six months ended June 30, 2012 and 2011 (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Basic and diluted weighted average units outstanding:				
Weighted average limited partner common units outstanding	55,998	50,563	53,427	50,518

All common unit equivalents were antidilutive in the three and six months ended June 30, 2012 and June 30, 2011 because the limited partners were allocated net losses in these periods.

The general partner is entitled to a 2.0% distribution with respect to all distributions made to common unitholders. If the distributions are in excess of $0.2125 per unit, distributions are made 98.0% to the common and preferred unitholders and 2.0% to the general partner, 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 2.0% 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 2.0% 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 Partnership's 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 June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Income allocation for incentive distributions	$ 1,130	$ 599	$ 2,108	$ 997
Stock-based compensation attributable to CEI's restricted shares	(1,144)	(759)	(2,276)	(1,700)
2% general partner interest in net income (loss)	(26)	49	57	70
General partner share of net loss	$ (40)	$ (111)	$ (111)	$ (633)

(5) Employee Incentive Plans

(a) Long-Term Incentive Plans

The Partnership accounts for share-based compensation in accordance with FASB ASC 718, which requires compensation related to all stock-based awards, including stock options, be recognized in the consolidated financial statements.

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 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 June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Cost of share-based compensation charged to general and administrative expense	$ 2,179	$ 1,540	$ 4,353	$ 3,266
Cost of share-based compensation charged to operating expense	316	265	640	729
Total amount charged to income	$ 2,495	$ 1,805	$ 4,993	$ 3,995

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(b) Restricted Units

The restricted 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 unit activity for the six months ended June 30, 2012 is provided below:

Six Months Ended June 30, 2012

Crosstex Energy, L.P. Restricted Units:	Number of Units	Weighted Average Grant-Date Fair Value
Non-vested, beginning of period	949,844	$ 10.45
Granted	352,912	16.53
Vested*	(232,700)	6.91
Forfeited	(13,954)	12.73
Non-vested, end of period	1,056,102	$ 13.23
Aggregate intrinsic value, end of period (in thousands)	$ 17,320	

* Vested units include 60,401 units withheld for payroll taxes paid on behalf of employees.

The Partnership issued restricted units in 2012 to officers and other employees. These restricted units typically vest at the end of three years and are included in the restricted units outstanding and the current share-based compensation cost calculations at June 30, 2012.

A summary of the restricted units' aggregate intrinsic value (market value at vesting date) and fair value of units vested (market value at date of grant) during the three and six months ended June 30, 2012 and 2011 are provided below (in thousands):

Crosstex Energy, L.P. Restricted Units:	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Aggregate intrinsic value of units vested	$ 280	$ 1,870	$ 3,806	$ 6,109
Fair value of units vested	$ 281	$ 2,383	$ 1,608	$ 5,556

As of June 30, 2012, there was $7.6 million of unrecognized compensation cost related to non-vested restricted units. That cost is expected to be recognized over a weighted-average period of 1.6 years.

(c) Unit Options

A summary of the unit option activity for the six months ended June 30, 2012 is provided below:

Crosstex Energy, L.P. Unit Options:	Six Months Ended June 30, 2012 Number of Units	Six Months Ended June 30, 2012 Weighted Average Exercise Price
Outstanding, beginning of period	451,574	$ 6.99
Exercised	(40,246)	5.06
Forfeited	(10,433)	16.34
Outstanding, end of period	400,895	$ 6.95
Options exercisable at end of period	334,326	
Weighted average contractual term (years) end of period:		
Options outstanding	6.7	
Options exercisable	6.5	
Aggregate intrinsic value end of period (in thousands):		
Options outstanding	$ 4,201	
Options exercisable	$ 3,508	

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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 six months ended June 30, 2012 and June 30, 2011 are provided below (in thousands):

Crosstex Energy, L.P. Unit Options:	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Intrinsic value of unit options exercised	$ 67	$ 479	$ 478	$ 985
Fair value of unit options vested	$ —	$ 236	$ 277	$ 561

As of June 30, 2012, there was $0.1 million of unrecognized compensation cost related to non-vested unit options. That cost is expected to be recognized over a weighted average period of 0.5 years.

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

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 six months ended June 30, 2012 is provided below:

Crosstex Energy, Inc. Restricted Shares:	Six Months Ended June 30, 2012 Number of Shares	Six Months Ended June 30, 2012 Weighted Average Grant-Date Fair Value
Non-vested, beginning of period	1,221,351	$ 7.40
Granted	454,146	13.28
Vested*	(244,195)	5.18

Forfeited	(18,850)	8.60
Non-vested, end of period	1,412,452	$ 9.66
Aggregate intrinsic value, end of period (in thousands)	$ 19,774	

* Vested shares include 58,247 shares withheld for payroll taxes paid on behalf of employees.

CEI issued restricted shares in 2012 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 June 30, 2012.

A summary of the restricted shares' aggregate intrinsic value (market value at vesting date) and fair value of shares vested (market value at date of grant) during the three and six months ended June 30, 2012 and June 30, 2011 are provided below (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
Crosstex Energy, Inc. Restricted Shares:	**2012**	**2011**	**2012**	**2011**
Aggregate intrinsic value of shares vested	$ 391	$ 1,111	$ 3,127	$ 3,689
Fair value of shares vested	$ 260	$ 2,391	$ 1,266	$ 5,281

As of June 30, 2012 there was $7.6 million of unrecognized compensation costs related to CEI non-vested restricted shares. The cost is expected to be recognized over a weighted average period of 1.6 years.

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(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 June 30, 2012.

(6) 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.

The Partnership commonly enters into various derivative financial transactions which it does not designate as accounting hedges. These transactions include "swing swaps," "third party on-system financial 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. Third party on-system financial swaps are hedges that the Partnership enters into on behalf of its customers who are connected to its systems, wherein the Partnership fixes a supply or market price for a period of time for its customers, and simultaneously enters into the derivative transaction. 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). 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 (POL) 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.

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 June 30,		Six Months Ended June 30,	
	2012	**2011**	**2012**	**2011**
Change in fair value of derivatives that do not qualify for hedge accounting	$ (7,095)	$ (825)	$ (5,913)	$ 730
Realized losses on derivatives	2,213	2,368	3,238	4,128
Ineffective portion of derivatives qualifying for hedge accounting	(23)	(101)	(61)	(82)
Net (gains) losses related to commodity swaps	$ (4,905)	$ 1,442	$ (2,736)	$ 4,776
Put option premium mark to market	—	94	—	181
(Gains) losses on derivatives	$ (4,905)	$ 1,536	$ (2,736)	$ 4,957

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

	June 30, 2012	**December 31, 2011**
Fair value of derivative assets — current, designated	$ 1,568	$ 151
Fair value of derivative assets — current, non-designated	5,112	2,716
Fair value of derivative assets — long term, designated	125	—
Fair value of derivative assets — long term, non-designated	1,479	—
Fair value of derivative liabilities — current, designated	—	(702)
Fair value of derivative liabilities — current, non-designated	(2,839)	(4,885)
Fair value of derivative liabilities — long term, non-designated	(7)	—
Net fair value of derivatives	$ 5,438	$ (2,720)

CROSSTEX ENERGY, L.P.

Notes to Condensed Consolidated Financial Statements

Set forth below is the summarized notional volumes and fair value of all instruments held for price risk management purposes and related physical offsets as of June 30, 2012 (all gas volumes are expressed in MMBtu's and liquids volumes are expressed in gallons). The remaining term of the contracts extend no later than December 2013 for derivatives. Changes in the fair value of the Partnership's mark to market derivatives are recorded in earnings in the period the transaction is entered into. The effective portion of changes in the fair value of cash flow hedges is recorded in accumulated other comprehensive income until the related anticipated future cash flow is recognized in earnings. The ineffective portion is recorded in earnings immediately.

Transaction Type	June 30, 2012 Volume	June 30, 2012 Fair Value
	(In thousands)	
*Cash Flow Hedges:**		
Liquids swaps (short contracts)	(5,705)	$ 1,693
Total swaps designated as cash flow hedges		$ 1,693
*Mark to Market Derivatives:**		
Swing swaps (long contracts)	419	$ 3
Physical offsets to swing swap transactions (short contracts)	(419)	—
Swing swaps (short contracts)	(4,588)	(35)
Physical offsets to swing swap transactions (long contracts)	4,588	—
Basis swaps (long contracts)	2,501	(30)
Physical offsets to basis swap transactions (short contracts)	(2,501)	5,189
Basis swaps (short contracts)	(2,501)	15
Physical offsets to basis swap transactions (long contracts)	2,501	(6,624)
Third-party on-system swaps (long contracts)	155	—
Physical offsets to third-party on-system swap transactions (short contracts)	(155)	(22)
Processing margin hedges — liquids (short contracts)	(9,064)	4,210
Processing margin hedges — gas (long contracts)	1,188	(1,035)
Processing margin hedges — gas (short contracts)	(187)	240
Liquids swaps - non-designated (short contracts)	(4,393)	1,471
Storage swap transactions — gas (long contracts)	210	116
Storage swap transactions — gas (short contracts)	(290)	62
Storage swap transactions — liquids inventory (long contracts)	1,470	(25)
Storage swap transactions — liquids inventory (short contracts)	(4,830)	210
Total mark to market derivatives		$ 3,745

* All are gas contracts, volume in MMBtu's, except for liquids swaps (designated or non-designated) and processing margin hedges - liquids (volume in gallons).

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 June 30, 2012 of $13.5 million would be reduced to $12.1 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):

Increase (Decrease) in Midstream Revenue	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Liquids realized loss included in Midstream revenue	$ 407	$ (1,048)	$ 395	$ (1,708)

Natural Gas

As of June 30, 2012, the Partnership has no balances in accumulated other comprehensive income related to natural gas.

Liquids

As of June 30, 2012, an unrealized derivative fair value net gain of $1.7 million related to cash flow hedges of liquids price risk was recorded in accumulated other comprehensive income. Of that amount, a net gain of $1.6 million is expected to be reclassified into earnings through June 2013. 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 actively quoted prices. 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
June 30, 2012	$ 2,272	$ 1,473	$ —	$ 3,745

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

	June 30, 2012 Level 2	December 31, 2011 Level 2
Commodity Swaps*	$ 5,438	$ (2,720)
Total	$ 5,438	$ (2,720)

* Unrealized gains or losses on commodity derivatives qualifying for hedge accounting are recorded in accumulated other comprehensive income 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):

	June 30, 2012		December 31, 2011	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Fair value of 2022 Notes classified as current debt	$ 250,000	$ 246,720	$ —	$ —
Long-term debt	$ 762,357	$ 816,500	$ 798,409	$ 882,500
Obligations under capital lease	$ 26,831	$ 28,847	$ 28,367	$ 27,637

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 $48.0 million in borrowings under its revolving credit facility included in long-term debt as of June 30, 2012 and $85.0 million at December 31, 2011. 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 June 30, 2012 and December 31, 2011, the Partnership also had borrowings totaling $714.4 million and $713.4 million, net of discount, respectively, under the 2018 Notes with a fixed rate of 8.875% and $250.0 million as of June 30, 2012 under the 2022 Notes with a fixed rate of 7.125%. The fair value of all senior unsecured notes as of June 30, 2012 and December 31, 2011 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.

(8) 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. 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.

On June 7, 2010, Formosa Plastics Corporation, Texas, Formosa Plastics Corporation, America, Formosa Utility Venture, Ltd., and Nan Ya Plastics Corporation, America filed a lawsuit against Crosstex Energy, Inc., Crosstex Energy, L.P., Crosstex Energy GP, L.P., Crosstex Energy GP, LLC, Crosstex Energy Services, L.P., and Crosstex Gulf Coast Marketing, Ltd. in the 24th Judicial District Court of Calhoun County, Texas, asserting claims for negligence, *res ipsa loquitor*, products liability and strict liability relating to the alleged receipt by the plaintiffs of natural gas liquids into their facilities from facilities operated by the Partnership. The amended petition alleges that the plaintiffs have incurred at least $35.0 million in damages, including damage to equipment and lost profits. The Partnership has submitted the claim to its insurance carriers and intends to vigorously defend the lawsuit. The Partnership believes that any recovery would be within applicable policy limits. Although it is not possible to predict the ultimate outcome of this matter, the Partnership does not expect that an award in this matter will have a material adverse impact on its consolidated results of operations or financial condition.

At times, the Partnership's gas-utility and common carrier subsidiaries acquire pipeline easements and other property rights by exercising rights of eminent domain. 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 gas utility 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 $2.0 million related to this matter and reflected the related

expense in operating expenses in the fourth quarter of 2011. 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.

(9) 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) and the south Louisiana processing and NGL assets (PNGL). Operating activity for assets sold in the comparative periods that was not considered discontinued operations as well as intersegment eliminations is shown in the corporate segment.

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, its investment in HEP, and as of June 30, 2012, $245.1 million in restricted cash. (See note 2 in these notes to condensed consolidated financial statements for additional discussion of the restricted cash.)

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

	LIG	NTX	PNGL (In thousands)	Corporate	Totals
Three Months Ended June 30, 2012:					
Sales to external customers	$ 121,479	$ 61,236	$ 168,479	$ —	$ 351,194
Sales to affiliates	$ 60,415	$ 17,227	$ 40,243	$ (117,885)	$ —
Purchased gas and NGLs	$ (153,601)	$ (31,457)	$ (193,717)	$ 117,885	$ (260,890)
Operating expenses	$ (8,759)	$ (14,144)	$ (7,668)	$ —	$ (30,571)
Segment profit	$ 19,534	$ 32,862	$ 7,337	$ —	$ 59,733
Gain (loss) on derivatives	$ 4,541	$ (153)	$ 517	$ —	$ 4,905
Depreciation, amortization and impairments	$ (3,182)	$ (21,009)	$ (8,069)	$ (610)	$ (32,870)
Capital expenditures	$ 1,886	$ 20,295	$ 30,255	$ 1,076	$ 53,512
Identifiable assets	$ 279,140	$ 1,086,299	$ 498,888	$ 379,908	$ 2,244,235
Three Months Ended June 30, 2011:					

Sales to external customers	$ 219,479	$ 87,813	$ 218,443	$ —	$ 525,735
Sales to affiliates	23,728	21,295	207	(45,230)	—
Purchased gas and NGLs	(211,417)	(64,360)	(198,630)	45,230	(429,177)
Operating expenses	(8,902)	(12,108)	(6,903)	—	(27,913)
Segment profit	$ 22,888	$ 32,640	$ 13,117	$ —	$ 68,645
(Loss) gain on derivatives	$ (1,269)	$ (377)	$ 110	$ —	$ (1,536)
Depreciation, amortization and impairments	$ (4,026)	$ (18,744)	$ (7,828)	$ (1,038)	$ (31,636)
Capital expenditures	$ 1,129	$ 16,807	$ 5,555	$ 715	$ 24,206
Identifiable assets	$ 326,149	$ 1,112,750	$ 492,919	$ 73,652	$ 2,005,470
Six Months Ended June 30, 2012:					
Sales to external customers	$ 268,177	$ 125,917	$ 328,809	$ —	$ 722,903
Sales to affiliates	133,225	$ 48,711	$ 85,787	$ (267,723)	$ —
Purchased gas and NGLs	(342,822)	$ (81,478)	$ (376,269)	$ 267,723	$ (532,846)
Operating expenses	(16,696)	$ (27,295)	$ (14,387)	$ —	$ (58,378)
Segment profit	$ 41,884	$ 65,855	$ 23,940	$ —	$ 131,679
Gain (loss) on derivatives	$ 4,643	$ (2,416)	$ 509	$ —	$ 2,736
Depreciation, amortization and impairments	$ (6,335)	$ (41,442)	$ (16,028)	$ (1,243)	$ (65,048)
Capital expenditures	$ 1,888	$ 33,451	$ 45,917	$ 1,536	$ 82,792
Identifiable assets	$ 279,140	$ 1,086,299	$ 498,888	$ 379,908	$ 2,244,235
Six Months Ended June 30, 2011:					
Sales to external customers	$ 424,397	$ 168,779	$ 422,329	$ —	$ 1,015,505
Sales to affiliates	46,050	42,880	692	(89,622)	—
Purchased gas and NGLs	(406,920)	(127,519)	(384,294)	89,622	(829,111)
Operating expenses	(16,969)	(23,460)	(12,528)	—	(52,957)
Segment profit	$ 46,558	$ 60,680	$ 26,199	$ —	$ 133,437
(Loss) gain on derivatives	$ (3,954)	$ (1,094)	$ 91	$ —	$ (4,957)
Depreciation, amortization and impairments	$ (7,168)	$ (36,464)	$ (15,541)	$ (2,116)	$ (61,289)
Capital expenditures	$ 2,679	$ 35,011	$ 9,636	$ 1,202	$ 48,528
Identifiable assets	$ 326,149	$ 1,112,750	$ 492,919	$ 73,652	$ 2,005,470

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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 June 30,		Six Months Ended June 30,	
	2012	**2011**	**2012**	**2011**
Segment profits	$ 59,733	$ 68,645	$ 131,679	$ 133,437
General and administrative expenses	(12,965)	(12,643)	(27,928)	(24,399)
Gain (loss) on derivatives	4,905	(1,536)	2,736	(4,957)
Gain on sale of property	406	60	504	80
Depreciation, amortization and impairments	(32,870)	(31,636)	(65,048)	(61,289)
Operating income	$ 19,209	$ 22,890	$ 41,943	$ 42,872

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Item 2. ***Management's Discussion and Analysis of Financial Condition and Resultsof 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. Our primary focus is on the gathering, processing, transmission and marketing of natural gas and natural gas liquids (NGLs), which we manage as regional reporting segments of midstream activity. We recently added crude oil terminal facilities in south Louisiana to provide access for crude oil producers to the premium markets in this area. Our geographic focus is in the north Texas Barnett shale (NTX) and in Louisiana which has two reportable business segments (the pipelines and processing plants located in Louisiana, or LIG, and the south Louisiana processing and NGL assets, or PNGL). During 2011, we gained a presence in the Permian Basin in west Texas through a joint project with Apache Corporation, which is included in our NTX segment and also gained access in the Eagle Ford shale in south Texas by our equity investment in Howard Energy Partners ("HEP"), which is included with our corporate assets for segment reporting.

We manage our operations by focusing on gross operating margin because our business is generally to purchase and resell natural gas and NGLs for a margin, or to gather, process, transport or market natural gas and NGLs for a fee. We earn a volume based fee for providing crude oil services. We define gross operating margin as operating revenue minus cost of purchased gas and NGLs. Gross operating margin is a 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 and the volumes of crude oil handled at our crude terminals. We generate revenues from five 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; and
- providing crude oil terminal 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 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 $8.5 million during the six months ended June 30, 2012 on the Delivery Contract. We currently expect that we will record an additional loss of approximately $8.5 million to $10.5 million on the Delivery Contract for the remainder of the year ending December 31, 2012. This estimate is based on forward prices, basis spreads and other market assumptions as of June 30, 2012. These assumptions are subject to change if market conditions change during the remainder of 2012, and actual results under the Delivery Contract in 2012 could be substantially different from our current estimates, which may result in a greater loss than currently estimated.

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 or liquids moved through 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

Credit Facility. In January 2012, we amended our credit facility. This amendment increased our borrowing capacity from $485.0 million to $635.0 million and amended certain terms in the facility to provide additional financial flexibility during the remaining four-year term of the facility as described in Part II, "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation — Indebtedness" in our Annual Report on Form 10-K for the year ended December 31, 2011.

In May 2012, we amended our credit facility. The amendment to our credit facility, among other things, (i) increased 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) during the Clearfield acquisition period (as defined in the amended credit facility, being generally the four quarterly measurement periods after closing the Clearfield Acquisition) from 5.0 to 1.0 to 5.5 to 1.0, and (ii) increased the maximum permitted consolidated leverage ratio during any other acquisition period (as defined in the amended credit facility, being generally the three quarterly measurement periods after closing certain material acquisitions) from 5.0 to 1.0 to 5.5 to 1.0.

Issuance of Common Units. On May 15, 2012, we issued 10,200,000 common units representing limited partner interests in the Partnership at a public offering price of $16.28 per unit for net proceeds of $158.0 million. In addition, Crosstex Energy GP, LLC made a general partner contribution of $3.4 million in connection with the issuance to maintain its 2% general partner interest. The net proceeds from the common unit offering were used for general partnership purposes.

2022 Notes. On May 24, 2012, we issued $250.0 million in aggregate principal amount of 7.125% senior unsecured notes (the "2022 Notes") due on June 1, 2022 at an issue price of 100% of the principal amount to yield 7.125% to maturity. The interest payments are due semi-annually in arrears in June and December. We placed into escrow the net proceeds of $245.1 million from the offering of the 2022 Notes pending completion of the Clearfield acquisition. The net proceeds are classified as restricted cash as of June 30, 2012 and the 2022 Notes are classified as current debt as of June 30, 2012. Upon closing of the Clearfield acquisition on July 2, 2012, the 2022 Notes were reclassified as long term debt and the restricted cash was used to fund the acquisition and for general partnership purposes, including capital expenditures for the Cajun-Sibon natural gas liquids pipeline expansion.

Investment in Limited Liability Company. On June 22, 2011, we entered into a limited liability agreement with Howard Energy Partners ("HEP") for an initial capital contribution of $35.0 million in exchange for an individual ownership interest in HEP. In 2012, we made an additional capital contribution of $52.3 million to HEP related to HEP's acquisition of substantially all of Meritage Midstream Services' natural gas gathering assets in south Texas. HEP owns midstream assets and provides midstream and construction services to Eagle Ford Shale producers. We own 30.6 percent of HEP and account for this investment under the equity method of accounting. This investment is reflected on the balance sheet as "Investment in limited liability company."

Clearfield Acquisition. On July 2, 2012, we completed our previously announced acquisition of all of the issued and outstanding common stock of Clearfield Energy, Inc. and Clearfield Energy's wholly-owned subsidiaries (collectively, "Clearfield"). Clearfield is a crude oil, condensate and water services company with operations in Ohio, Kentucky and West Virginia.

Clearfield's assets include a 4,500-barrel-per-hour crude oil barge loading terminal on the Ohio River, a 28,000-barrel-per day crude oil rail loading terminal on the Ohio Central Railroad network, and approximately 200 miles of crude oil pipelines in Ohio and West Virginia. The assets also include 500,000 barrels of above ground storage, six existing brine water disposal wells with two under development and an extensive fleet of trucks. In addition, Clearfield owns more than 2,500 miles of unused right of way.

The Partnership paid approximately $210.0 million in cash for the acquisition and the acquisition was funded from restricted cash that resulted from the 2022 Notes offering. The assets associated with this acquisition will be included in a new reporting segment that will be referred to as Ohio River Valley. Pro-forma financial statements for the Clearfield acquisition are available on the Partnership's amended Current Report on Form 8-K/A filed on August 1, 2012.

Riverside Fractionation Facility Expansion. On May 7, 2012, the Partnership announced its plans to increase its capacity to transload crude oil from rail cars to both barges and pipeline at its Riverside fractionation facility in southern Louisiana from approximately 4,500 barrels of crude oil per day to approximately 15,000 barrels of crude per day. The Phase I modification of the Riverside facility, which allowed crude as well as NGLs to be transloaded from rail to barge, was operational in January 2012. The Phase II development at the Riverside facility will include new storage tank facilities, upgraded pipeline connections and improved barge delivery capabilities on the Mississippi River. Construction of the Phase II expansion project at Riverside began in late June 2012 and is expected be operational in the first quarter of 2013. The expansion project is expected to cost approximately $16 million. The Partnership has entered into a long-term agreement, which supports the expansion.

Non-GAAP Financial Measures

We include the following non-generally accepted accounting principles, or 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, costs related to acquisitions, (gain) loss on noncash derivatives, and minority interest; less gain on sale of property. 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.

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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 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) income to adjusted EBITDA:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(In millions)			
Net (loss) income attributable to Crosstex Energy, L.P.	$ (2.4)	$ 1.7	$ 0.5	$ 1.8
Interest expense	21.3	20.7	40.7	40.4
Depreciation and amortization	32.9	31.6	65.0	61.3
Gain on sale of property	(0.4)	(0.1)	(0.5)	(0.1)
Stock-based compensation	2.5	1.8	5.0	4.0
Other (a)	(5.2)	(0.3)	(3.5)	1.6
Adjusted EBITDA	$ 48.7	$ 55.4	$ 107.2	$ 109.0

(a) Includes financial derivatives marked-to-market; income taxes; minority interest; and acquisition costs.

We define gross operating margin, generally, as revenues minus cost of purchased gas and NGLs. 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 for a margin or to gather, process, transport or market natural gas and NGLs 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. These expenses are largely independent of the volumes we transport or process and fluctuate depending on the activities performed during a specific period. We do not deduct operating expenses from total revenue in calculating gross operating margin because we separately evaluate commodity volume and price changes in these margin amounts. 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:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(In millions)			
Total gross operating margin	$ 90.3	$ 96.6	$ 190.1	$ 186.4
Add (deduct):				
Operating expenses	(30.6)	(27.9)	(58.4)	(53.0)
General and administrative expenses	(13.0)	(12.6)	(27.9)	(24.4)
Gain on sale of property	0.4	0.1	0.5	0.1
Gain (loss) on derivatives	4.9	(1.5)	2.7	(5.0)
Depreciation and amortization	(32.9)	(31.8)	(65.0)	(61.2)
Operating income	$ 19.1	$ 22.9	$ 42.0	$ 42.9

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Results of Operations

Set forth in the table below is certain financial and operating data for the periods indicated. We manage our operations by focusing on gross operating margin which we define as operating revenue minus cost of purchased gas and NGLs as reflected in the table below.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(Dollars in millions)			
LIG Segment				
Revenues	$ 181.9	$ 243.2	$ 401.4	$ 470.4
Purchased gas and NGLs	(153.6)	(211.4)	(342.8)	(406.9)
Total gross operating margin	$ 28.3	$ 31.8	$ 58.6	$ 63.5
NTX Segment				
Revenues	$ 78.5	$ 109.1	$ 174.6	$ 211.7
Purchased gas and NGLs	(31.5)	(64.4)	(81.5)	(127.5)
Total gross operating margin	$ 47.0	$ 44.7	$ 93.1	$ 84.2
PNGL Segment				
Revenues	$ 208.7	$ 218.7	$ 414.6	$ 423.0
Purchased gas and NGLs	(193.7)	(198.6)	(376.3)	(384.3)
Total gross operating margin	$ 15.0	$ 20.1	$ 38.3	$ 38.7
Corporate				
Revenues	$ (117.9)	$ (45.2)	$ (267.7)	$ (89.6)
Purchased gas and NGLs	117.9	45.2	267.7	89.6
Total gross operating margin	$ —	$ —	$ —	$ —
Total				
Revenues	$ 351.2	$ 525.8	$ 722.9	$ 1,015.5
Purchased gas and NGLs	(260.9)	(429.2)	(532.8)	(829.1)
Total gross operating margin	$ 90.3	$ 96.6	$ 190.1	$ 186.4
Midstream Volumes:				
LIG				
Gathering and Transportation (MMBtu/d)	802,000	923,000	851,000	931,000
Processing (MMBtu/d)	249,000	236,000	256,000	247,000
NTX				
Gathering and Transportation (MMBtu/d)	1,188,000	1,184,000	1,184,000	1,119,000
Processing (MMBtu/d)	351,000	269,000	334,000	243,000
PNGL				
Processing (MMBtu/d)	833,000	881,000	854,000	901,000
NGL Fractionation (Gals/d)	1,320,000	1,145,000	1,251,000	1,139,000
Commercial Services (MMBtu/d)	11,000	85,000	12,000	99,000

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

Gross Operating Margin. Gross operating margin was $90.3 million for thethree months ended June 30, 2012 compared to $96.6 million for the three months ended June 30, 2011, a decrease of $6.3 million, or 6.5%. The decrease was primarily due to gross operating margin declines in the processing business due to a less favorable NGL market. The decrease was partially offset by gross operating margins generated from increased gathering and processing activity in our north Texas region. The following provides additional details regarding this change in gross operating margin:

- The NTX segment had gross operating margin improvement of $2.3 million for the three months ended June 30, 2012 compared to the three months ended June 30,

2011. An increase in throughput volume on the gathering and transmission assets in north Texas due to the Benbrook and Fossil Creek expansion projects was the primary contributor to a gross operating margin increase of $1.7 million. The north Texas processing plants also had a gross operating margin increase of $0.4 million for the comparable periods due to increased supply from the expansion projects which offset the negative margin impact caused by less favorable NGL markets during 2012 as compared to the same period in 2011. In addition, the Permian Basin commenced gas processing facilities, which came online in the first quarter of 2012 and contributed $1.7 million to gross operating margin. These increases were partially offset by an increase in losses of $1.6 million on the Delivery Contract discussed more fully under "Overview".

- The PNGL segment had a gross operating margin decrease of $5.1 million for the three months ended June 30, 2012 compared to the three months ended June 30, 2011. The weaker processing environment contributed to a significant decline in the gross operating margins for processing plants during the three months ended June 30, 2012. Overall, the south Louisiana processing plants reported a combined gross operating margin decrease of approximately $6.0 million. This decrease was partially offset by our new crude oil terminal activity in south Louisiana, which contributed $1.0 million to PNGL's gross operating margin during the three months ended June 30, 2012.

- The LIG segment contributed a decrease in gross operating margin of $3.5 million for the three months ended June 30, 2012 compared to the three months ended June 30, 2011. The weaker processing environment contributed to a significant decline in the gross operating margins for our processing activities during the three months ended June 30, 2012. Gross operating margins decreased by $1.1 million from our Plaquemine and Gibson plants and decreased by $5.5 million from gas processed for our account by a third-party processor between periods. These decreases were partially offset by an increase in gross operating margins of $3.1 million on the LIG gathering and transmission assets.

Operating Expenses. Operating expenses were $30.6 million for the three months ended June 30, 2012 compared to $27.9 million for the three months ended June 30, 2011, an increase of $2.7 million, or 9.5%. The increase is primarily a result of the following:

- our labor and benefits expense increased by $0.8 million related to an increase in employee headcount for activity related to project expansions in the North Texas segment, including the Permian Basin processing facilities, and the PNGL segment which was offset by a $0.7 million decrease in bonus expense;
- our materials, supplies and contractor cost increased by $2.0 million related to compressor overhauls and required maintenance activities performed in 2012;
- our fees and services increased by $0.6 million related to litigation costs and project expansion activities;
- our ad valorem tax expense increased by $0.2 million due to project expansions; and
- our lease expense decreased by $0.4 million related to decreased use of leased compressors.

General and Administrative Expenses. General and administrative expenses were $13.0 million for the three months ended June 30, 2012 compared to $12.6 million for the three months ended June 30, 2011, an increase of $0.3 million, or 2.5%. The increase is primarily due to the following:

- our salaries and wages increased by $0.5 million due to an increase in headcount offset by a decrease of $2.3 million in bonus expense;
- our bad debt expense increased by $0.3 million;
- our stock based compensation expense increased by $0.6 million; and
- our fees and services increased by $1.4 million primarily related to closing the Clearfield acquisition and diligence.

Gain/Loss on Derivatives. We had a gain on derivatives of $4.9 million for the three months ended June 30, 2012 compared to a loss of $1.5 million for the three months ended June 30, 2011. The derivative transaction types contributing to the net (gain) loss are as follows (in millions):

	Three Months Ended June 30,			
	2012		2011	
	Total	Realized	Total	Realized
Basis swaps	$ 1.2	$ 1.5	$ 0.4	$ 0.4
Processing margin hedges	(4.4)	0.7	1.3	2.0
Other	(1.7)	—	(0.2)	—
Net (gains) losses related to commodity swaps	$ (4.9)	$ 2.2	$ 1.5	$ 2.4

Depreciation and Amortization. Depreciation and amortization expenses were $32.9 million for the three months ended June 30, 2012 compared to $31.6 million for the three months ended June 30, 2011, an increase of $1.2 million, or 3.9%. The increase includes $1.6 million due to intangible amortization related to the downward revision in future estimated throughput volumes attributable to the dedicated acreage purchased with our gathering system in North Texas. In addition, depreciation decreased by $0.4 million due primarily to accelerated depreciation on abandoned projects in 2011 offset by net additions to assets placed in service during 2012.

Interest Expense. Interest expense was $21.3 million for the three months ended June 30, 2012 compared to $20.7 million for the three months ended June 30, 2011, an increase of $0.6 million, or 2.9%. Net interest expense consists of the following (in millions):

	Three Months Ended June 30,	
	2012	2011
Senior notes	$ 18.0	$ 16.6
Bank credit facility	1.3	1.3
Amortization of debt issue costs	1.8	2.5
Other	0.2	0.3
Total	$ 21.3	$ 20.7

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

Gross Operating Margin. Gross operating margin was $190.1 million for the six months ended June 30, 2012 compared to $186.4 million for the six months ended June 30, 2011, an increase of $3.7 million, or 2.0%. The increase was due to increased gross operating margins from our gathering and transmission assets partially offset by declines in margins from our processing activities due to less favorable NGL markets during 2012. The following provides additional details regarding this change in gross operating margin:

- The NTX segment had a gross operating margin increase of $9.0 million for the six months ended June 30, 2012 compared to the six months ended June 30, 2011. An increase in throughput volume on the gathering and transmission assets in north Texas due to the Benbrook and Fossil Creek expansion projects was the primary contributor to a gross operating margin increase of $6.2 million. The north Texas processing plants also had a gross operating margin increase of $2.8 million for the comparable periods due to increased supply from the expansion projects. In addition, the gas processing facilities located in the Permian Basin contributed $2.5 million to gross operating margin. These increases were partially offset by an increase in losses of $2.5 million on the Delivery Contract discussed more fully under "Overview."

- The PNGL segment had a decrease in gross operating margin of $0.4 million for the six months ended June 30, 2012 compared to the six months ended June 30, 2011.

The weaker processing environment during the second quarter of 2012 contributed to a decline in the gross operating margins for processing activities during the six months ended June 30, 2012. Overall, the south Louisiana processing plants reported a combined gross operating margin decrease of approximately $4.7 million between periods. This decrease was partially offset by an increase of $2.5 million in gross operating margin from our NGL fractionation and marketing activity. The primary contributor to the gross operating margin increase from our NGL activities was $2.9 million from the Eunice fractionator which was restarted in mid-2011. The PNGL segment also includes our new crude terminal activity in south Louisiana which contributed $1.8 million to the PNGL's gross operating margin for the six months ended June 30, 2012.

- The LIG segment had a gross operating margin decrease of $4.9 million for the six months ended June 30, 2012 compared to the six months ended June 30, 2011. The weaker processing environment during the second quarter of 2012 contributed to a decline in the gross operating margins for processing activities during the six months ended June 30, 2012. Gross operating margins decreased by $0.3 million from our Plaquemine and Gibson plants and decreased by $9.8 million from gas processed for our account by a third-party processor between periods. These decreases were partially offset by an increase in gross operating margins of $5.1 million on the LIG gathering and transmission assets.

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Operating Expenses. Operating expenses were $58.4 million for the six months ended June 30, 2012 compared to $53.0 million for the six months ended June 30, 2011, an increase of $5.4 million, or 10.2%. The increase is primarily a result of the following:

- our labor and benefits expense increased by $1.7 million related to an increase in employee headcount for activities related to project expansions in the North Texas segment, including the Permian Basin processing facilities, and the PNGL segment, which was partially offset by a $1.3 million reduction in bonus expense;
- our materials, supplies and contractor cost increased by $2.8 million related to compressor overhauls and required maintenance activities performed in 2012;
- our fees and services increased by $1.0 million related to litigation costs and project expansion activities;
- our ad valorem tax expense increased by $0.9 million due to project expansions; and
- our lease expense decreased by $0.6 million related to decreased use of leased compressors.

General and Administrative Expenses. General and administrative expenses were $27.9 million for the six months ended June 30, 2012 compared to $24.4 million for the six months ended June 30, 2011, an increase of $3.5 million, or 14.5%. The increase is primarily a result of the following:

- our salaries, wages, and benefits increased by $1.6 million due to an increase in headcount offset by a decrease of $2.2 million in bonus expense;
- our stock based compensation expense increased by $1.0 million; and
- our fees and services increased by $2.5 million related to legal and other professional fees of which $1.3 million relates to our recent Clearfield acquisition.

Gain/Loss on Derivatives. Gain on derivatives was $2.7 million for the six months ended June 30, 2012 compared to a loss of $5.0 million for the six months ended June 30, 2011. The derivative transaction types contributing to the net loss are as follows (in millions):

	Six Months Ended June 30,			
	2012		2011	
	Total	Realized	Total	Realized
Basis swaps	$ 3.5	$ 2.2	$ 1.0	$ 1.1
Processing margin hedges	(4.2)	1.6	4.0	3.2
Other	(2.0)	(0.6)	—	(0.2)
Net (gains) losses related to commodity swaps	$ (2.7)	$ 3.2	$ 5.0	$ 4.1

Depreciation and Amortization. Depreciation and amortization expenses were $65.0 million for the six months ended June 30, 2012 compared to $61.3 million for the six months ended June 30, 2011, an increase of $3.7 million, or 6.1%. The increase includes $3.4 million due to intangible amortization related to the downward revision in future estimated throughput volumes attributable to the dedicated acreage purchased with our gathering system in North Texas. In addition, depreciation expense increased $0.3 million primarily due to an increase of assets placed in service during 2012.

Interest Expense. Interest expense was $40.7 million for the six months ended June 30, 2012 compared to $40.4 million for the six months ended June 30, 2011. Net interest expense consists of the following (in millions):

	Six Months Ended June 30,	
	2012	2011
Senior notes	$ 34.1	$ 33.1
Bank credit facility	4.5	2.5
Amortization and write off of debt issue costs	2.5	4.1
Other	(0.4)	0.7
Total	$ 40.7	$ 40.4

Critical Accounting Policies

Information regarding the Partnership's Critical Accounting Policies is included in Item 7 of the Partnership's Annual Report on Form 10-K for the year ended December 31, 2011.

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Liquidity and Capital Resources

Cash Flows from Operating Activities. Net cash provided by operating activities was $52.3 million for the six months ended June 30, 2012 compared to net cash provided by operating activities of $65.2 million for six months ended June 30, 2011. Income before non-cash income and expenses and changes in working capital for comparative periods were as follows (in millions):

	Six Months Ended June 30,	
	2012	2011
Income before non-cash income and expenses	$ 66.0	$ 72.7

Changes in working capital	$ (13.7)	$ (7.6)

The decrease in cash flow from income before non-cash income and expenses of $6.7 million resulted from a decrease in gross operating margin from six months ended June 30, 2012 compared to six months ended June 30, 2011.

Cash Flows from Investing Activities. Net cash used in investing activities was $141.7 million for the six months ended June 30, 2012 and $84.5 million for the six months ended June 30, 2011. Our primary investing outflows were capital expenditures, net of accrued amounts, as follows (in millions):

	Six Months Ended June 30,	
	2012	2011
Growth capital expenditures	$ 83.4	$ 44.4
Maintenance capital expenditures	6.6	5.2
Investment in limited liability company	52.3	35.0
Total	$ 142.3	$ 84.6

Cash Flows from Financing Activities. Net cash provided by financing activities was $70.2 million for the six months ended June 30, 2012 and $4.0 million for the six months ended June 30, 2011. Our primary financing activities consist of the following (in millions):

	Six Months Ended June 30,	
	2012	2011
Net (repayments) borrowings on bank credit facility	$ (37.0)	$ 52.0
2022 Notes borrowings	250.0	—
Series B senior secured note repayment	—	(7.1)
Net repayments under capital lease obligations	(1.5)	(1.5)
Debt refinancing costs	(5.0)	(3.8)
Common unit offerings	158.0	—
Increase in restricted cash	(245.1)	—

Distributions to unitholders and our general partner also represent a primary use of cash in financing activities. Total cash distributions made during the six months ended June 30, 2012 and 2011 were as follows (in millions):

	Six Months Ended June 30,	
	2012	2011
Common units	$ 33.7	$ 28.3
Preferred units	9.5	8.1
General partner interest (including incentive distribution rights)	2.7	1.2
Total	$ 45.9	$ 37.6

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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 June 30, 2012, we had approximately $529.4 million of available borrowing capacity under our credit facility. Changes in drafts payable for the six months ended June 30, 2012 and 2011 were as follows (in millions):

	Six Months Ended June 30,	
	2012	2011
(Decrease) increase in drafts payable	$ (6.0)	$ 3.2

Working Capital. We had a working capital deficit of $9.2 million as of June 30, 2012. 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 are collected and a large volume of our gas purchases are 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 and NGLs 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 and NGL 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 and NGL prices.

Potential Changes in Operations During 2012. Currently, the Partnership's Sabine plant has a contract with a third-party to fractionate the raw-make NGLs produced by the plant. The primary term of the contract expired on June 30, 2012 and is currently renewed on a month-to-month basis. The Partnership will negotiate with this third-party to establish a long-term fractionation agreement. If this third-party ceases to fractionate the produced NGLs from the Sabine plant after June 30, 2012 and the Partnership is unsuccessful in determining another alternative for its Sabine customers, the Partnership will cease operation of the Sabine plant. Although the Partnership does not have specific plans at this time to relocate the Sabine plant if it is idled, the Partnership may utilize it elsewhere in its operations. The net book value of the Sabine plant was $46.4 million (including $13.3 million of intangible assets attributable to customer relationships) as of June 30, 2012. If the plant is idled on a long-term basis, an impairment may be recorded to expense the non-recoverable costs associated with the plant's current location, which are estimated to be approximately $27.0 million based on the net book value as of June 30, 2012.

The Partnership has a gas gathering contract with a major producer in our North Texas assets that is set to expire on August 31, 2012 and will be on a month-to-month basis beginning September 1, 2012. We are negotiating with this producer to continue to provide gathering services on a long-term basis but we anticipate that such future gathering services, if any, will be provided at lower rates and volumes than currently under contract. Gross operating margins from this producer were $11.0 million for the six months ended June 30, 2012. In the event production on this system is significantly reduced due to the expiration of this contract, we will be able to reduce operating expenses to support the reduced operations although such cost reductions will not cover the margin decline.

Recently, a slurry filled sinkhole developed near our 36 inch pipeline in Napoleonville, Louisiana. Because of the proximity of the slurry to our system, we isolated and shut in a portion of the pipeline. The shut in will impact approximately 149,000 MMBtu/d of supply to the river markets. We have notified our customers and they have made arrangements to secure supply to avoid disruptions in this area. At this time, we are still assessing the financial impact.

Capital Requirements. During the six months ended June 30, 2012, capital investments were $142.3 million (including $52.3 million related to HEP), which were funded by internally generated cash flow and from borrowings under our credit facility. Our remaining 2012 projected capital spend for growth capital includes approximately $388.0 million related to project and acquisition expenditures which include $210.0 million for the Clearfield acquisition completed on July 2, 2012 and $111.5 million for Cajun-Sibon NGL pipeline expansion. 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 June 30, 2012.

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Total Contractual Cash Obligations. A summary of contractual cash obligations as of June 30, 2012 is as follows (in millions):

	Payments Due by Period						
	Total	2012	2013	2014	2015	2016	Thereafter
Long-term debt obligations (1)	$ 975.0	$ 250.0	$ —	$ —	$ —	$ —	$ 725.0
Bank credit facility	48.0	—	—	—	—	48.0	—
Interest payable on fixed long-term debt obligations	563.7	41.4	82.2	82.2	82.2	82.2	193.5
Capital lease obligations	32.8	2.3	4.6	4.6	4.6	4.6	12.1
Operating lease obligations	33.5	4.0	8.5	6.2	4.7	3.9	6.2
Purchase obligations	3.3	3.3	—	—	—	—	—
Uncertain tax position obligations	4.6	4.6	—	—	—	—	—
Total contractual obligations	$ 1,660.9	$ 305.6	$ 95.3	$ 93.0	$ 91.5	$ 138.7	$ 936.8

(1) See note 2 in these notes to condensed consolidated financial statements.

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 June 30, 2012, the cash obligation for interest expense on the Partnership's credit facility would be approximately $1.6 million per year or $0.8 million for the remainder of 2012.

Indebtedness

As of June 30, 2012 and December 31, 2011, long-term debt consisted of the following (in millions):

	June 30, 2012	December 31, 2011
Bank credit facility (due 2016), interest based on Prime and/or LIBOR plus an applicable margin, interest rate at June 30, 2012 and December 31, 2011 was 3.33% and 2.9%, respectively	$ 48.0	$ 85.0
Senior unsecured notes (due 2018), net of discount of $10.6 million and $11.6 million, respectively, which bear interest at the rate of 8.875%	714.4	713.4
Senior unsecured notes (due 2022), which bear interest at the rate of 7.125%	250.0	—
	1,012.4	798.4
Less current portion	(250.0)	—
Debt classified as long-term	$ 762.4	$ 798.4

Credit Facility. In January 2012, we amended our credit facility. This amendment increased our borrowing capacity from $485.0 million to $635.0 million and amended certain terms in the facility to provide additional financial flexibility during the remaining four-year term of the facility as described in Part II, "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Indebtedness" in our Annual Report on Form 10-K for the year ended December 31, 2011.

In May 2012, we amended our credit facility. The amendment to our credit facility, among other things, (i) increased 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) during the Clearfield acquisition period (as defined in the amended credit facility, being generally the four quarterly measurement periods after closing the Clearfield acquisition) from 5.0 to 1.0 to 5.5 to 1.0, and (ii) increased the maximum permitted consolidated leverage ratio during any other acquisition period (as defined in the amended credit facility, being generally the three quarterly measurement periods after closing certain material acquisitions) from 5.0 to 1.0 to 5.5 to 1.0.

As of June 30, 2012, our credit facility had a borrowing capacity of $635.0 million and there was $57.6 million in letters of credit issued and outstanding under the credit facility and $48.0 million of borrowings outstanding, leaving approximately $529.4 million available for future borrowing. The credit facility is guaranteed by substantially all of our subsidiaries. The credit facility matures in May 2016.

2022 Notes. On May 24, 2012, we issued $250.0 million in aggregate principal amount of 7.125% senior unsecured notes (the "2022 Notes") due on June 1, 2022 at an issue price of 100% of the principal amount to yield 7.125% to maturity. The interest payments are due semi-annually in arrears in June and December. We placed into escrow the net proceeds of $245.1 million from the offering of the 2022 Notes pending completion of the Clearfield acquisition. The net proceeds are classified as restricted cash as of June 30, 2012 and the 2022 Notes are classified as current debt as of June 30, 2012. Upon closing of the acquisition on July 2, 2012, the 2022 Notes were reclassified as long term debt and a portion of the restricted cash was used to fund the Clearfield acquisition and for general partnership purposes, including capital expenditures for the Cajun-Sibon natural gas liquids pipeline expansion.

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Recent Accounting Pronouncements

We have reviewed recently issued accounting pronouncements that became effective during the six months ended June 30, 2012, 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, 2011, 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 and NGLs. 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 Commodity Futures Trading Commission (the “CFTC”) to regulate certain markets for over-the-counter (“OTC”) derivative products. 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 to clear through clearinghouses. We may be affected by the cost of margin requirements and of certain clearing and trade-execution requirements in connection with our derivatives activities. The CFTC has adopted regulations that may provide to us the certainty that we will not be required to comply directly with margin requirements or clearing requirements. The rules could also impose burdens on market participants to such an extent that liquidity in the bilateral OTC derivative market decreases substantially. 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, including determinations with respect to the applicability of margin requirements and other trading structures, 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 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 and transportation margins as a percent of total gross operating margin for the comparative year-to-date periods are as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Gathering and transportation margin	63.6%	56.4%	60.6%	56.4%
Gas processing margins:				
Processing margin	9.0%	18.9%	13.7%	18.5%
Percent of liquids	10.9%	12.8%	9.2%	12.2%
Fee based	16.5%	11.9%	16.5%	12.9%
Total gas processing	36.4%	43.6%	39.4%	43.6%
Total	100.0%	100.0%	100.0%	100.0%

We have hedges in place at June 30, 2012 covering a portion of the liquids volumes we expect to receive under percent of liquids (POL) contracts. The hedges were done via swaps and are set forth in the following table. 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)
July 2012 — December 2012	Ethane	31 (MBbls)	Index	$ 0.4885 /gal	$ 213
July 2012 — December 2012	Propane	28 (MBbls)	Index	$ 1.2910 /gal	514
July 2012 — December 2012	Normal Butane	15 (MBbls)	Index	$ 1.7227 /gal	265
July 2012 — December 2012	Natural Gasoline	11 (MBbls)	Index	$ 2.3247 /gal	261

					$ 1,253

*weighted average

Period	Underlying	Notional Volume	We Pay	We Receive *	Fair Value Asset/(Liability) (In thousands)
January 2013 — December 2013	Ethane	63 (MBbls)	Index	$ 0.4533 /gal	$ 257
January 2013 — December 2013	Propane	45 (MBbls)	Index	$ 1.2622 /gal	726
January 2013 — December 2013	Normal Butane	27 (MBbls)	Index	$ 1.7966 /gal	530
January 2013 — December 2013	Natural Gasoline	20 (MBbls)	Index	$ 2.2795 /gal	398
					$ 1,911

*weighted average

We have hedged our exposure to declines in prices for NGL volumes produced for our account. The NGL volumes hedged, as set forth above, focus on our POL contracts. We hedge our POL exposure based on volumes we consider hedgeable (volumes committed

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under contracts that are long term in nature) versus total POL volumes that include volumes that may fluctuate due to contractual terms, such as contracts with month to month processing options. We have hedged 39.5% of our hedgeable volumes at risk through December 2012 (21.2% of total volumes at risk through December 2012). We have also hedged 39.6% of our hedgeable volumes at risk for 2013 (18.6% of total volumes at risk for 2013).

We also have hedges in place at June 30, 2012 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)
July 2012—December 2012	Ethane	28 (MBbls)	Index	$ 0.7025 /gal*	$ 459
July 2012—December 2012	Propane	41 (MBbls)	Index	$ 1.3368 /gal*	831
July 2012—December 2012	Normal Butane	25 (MBbls)	Index	$ 1.7416 /gal*	467
July 2012—December 2012	Natural Gasoline	20 (MBbls)	Index	$ 2.2309 /gal*	376
July 2012—December 2012	Natural Gas	2,723 (MMBtu/d)	$ 4.5752 /MMBtu*	Index	(803)
					$ 1,330

*weighted average

Period	Underlying	Notional Volume	We Pay	We Receive	Fair Value Asset/(Liability) (In thousands)
January 2013—December 2013	Propane	49 (MBbls)	Index	$ 1.3236 /gal*	$ 916
January 2013—December 2013	Normal Butane	29 (MBbls)	Index	$ 1.8653 /gal*	668
January 2013—December 2013	Natural Gasoline	23 (MBbls)	Index	$ 2.3217 /gal*	493
January 2013—December 2013	Natural Gas	1,370 (MMBtu/d)	$ 3.5605 /MMBtu*	Index	8
					$ 2,085

* weighted average

In relation to our fractionation spread risk, as set forth above, we have hedged 40.7% of our hedgeable liquids volumes at risk through December 31, 2012 (7.1% of total liquids volumes at risk) and 46.2% of the related hedgeable PTR volumes through December 31, 2012 (5.7% of total PTR volumes). We have also hedged 18.2% of our hedgeable liquids volumes at risk for 2013 (3.0% of total liquids volumes at risk) and 23.1% of the related hedgeable PTR volumes for 2013 (2.9% of total PTR volumes).

We are also 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 2.9% 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.

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.

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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 June 30, 2012, 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 $5.4 million. The aggregate effect of a hypothetical 10% increase in gas and NGL prices would result in a decrease of approximately $1.9 million in the net fair value asset of these contracts as of June 30, 2012 to a net fair value asset of approximately $3.5 million.

Interest Rate Risk

We are exposed to interest rate risk on our variable rate bank credit facility. At June 30, 2012, we had $48.0 million in borrowings under this facility. A 1% increase or decrease in interest rates would change our annual interest expense by approximately $0.4 million for the year.

At June 30, 2012, we had non-current fixed rate debt obligations of $714.4 million, consisting of our senior unsecured notes due 2018 with an interest rate of 8.875%. The fair value of this fixed rate obligation was approximately $768.5 million as of June 30, 2012. We estimate that a 1% increase or decrease in interest rates would increase or decrease the fair value of such debt by $32.6 million.

At June 30, 2012, we had current fixed rate debt obligations of $250.0 million, consisting of our senior unsecured notes due 2022 with an interest rate of 7.125%. The fair value of this fixed rate obligation was approximately $246.7 million as of June 30, 2012. We estimate that a 1% increase or decrease in interest rates would increase or decrease the fair value of such debt by $17.5 million.

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 (June 30, 2012), 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 our 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 six months ended June 30, 2012 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 8, "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 for the six months ended June 30, 2012 does not differ materially from that set forth in Part I, Item 1A, of our Annual Report on Form 10-K for the year ended December 31, 2011 except as listed below.

Recently proposed or finalized rules imposing more stringent requirements on the oil and gas industry could cause our customers and us to incur increased capital expenditures and operating costs as well as reduce the demand for our services.

On April 17, 2012, the U.S. Environmental Protection Agency ("EPA") approved final regulations under the Clean Air Act that, among other things, require additional emissions controls for natural gas and natural gas liquids production, including New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds ("VOCs") and a separate set of emission standards to address hazardous air pollutants frequently associated with such production activities. The final regulations require, among other things, the reduction of VOC emissions from natural gas wells through the use of reduced emission completions or "green completions" on all hydraulically fractured wells constructed or refractured after January 1, 2015. Moreover, these rules establish specific requirements regarding emissions from compressors and controllers at natural gas gathering and boosting stations and processing plants together with dehydrators and storage tanks at natural gas processing plants, compressor stations and gathering and boosting stations. The rules also establish new requirements for leak detection and repair of leaks at natural gas processing plants that exceed 500 parts per million in concentration. These regulations could require a number of modifications to our natural gas exploration and production customer's as well as our operations including the installation of new equipment, which could result in significant costs, including increased capital expenditures and operating costs. The incurrence of such expenditures and costs by our customers could result in reduced production by those customers and thus translate into reduced demand for our services.

In addition, federal agencies have recently initiated certain other regulatory initiatives or reviews of certain aspects of hydraulic fracturing that could further increase our natural gas exploration and production customer's costs and decrease their levels of production. On May 4, 2012, the federal Bureau of Land Management announced draft rules that, if adopted, would require disclosure of chemicals used in hydraulic fracturing activities upon Native American Indian and other federal lands. Moreover, in late 2011, the EPA announced that it is developing standards for the treatment and discharge of wastewater resulting from hydraulic fracturing activities and indicated that such standards would be proposed by 2014. The adoption and implementation of one or both of these rules could further result in increased expenditures for our natural gas exploration and production customers or us, and could result in reduced demand for our services by these customers.

The recent adoption of derivatives legislation by the United States Congress and promulgation of related regulations could have an adverse effect on our ability to hedge risks associated with our business.

Comprehensive financial reform legislation was signed into law by the President on July 21, 2010. The legislation calls for the Commodity Futures Trading Commission (the "CFTC") to regulate certain markets for over-the-counter ("OTC") derivative products. 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 to clear through clearinghouses. We may be affected by the cost of margin requirements and of certain clearing and trade-execution requirements in connection with our derivatives activities. The CFTC has adopted regulations that may provide to us the certainty that we will not be required to comply directly with margin requirements or clearing requirements. The rules could also impose burdens on market participants to such an extent that liquidity in the bilateral OTC derivative market decreases substantially. 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, including determinations with respect to the applicability of margin requirements and other trading structures, 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.

Item 5. Other Information

Certificate of Amendment to the Certificate of Limited Partnership

As previously disclosed, Crosstex Energy GP, L.P. merged with and into Crosstex Energy GP, LLC, thereby eliminating the separate existence of Crosstex Energy GP, L.P. In connection with such merger, Crosstex Energy GP, LLC became the general

partner of the Partnership. On August 6, 2012, the Partnership filed with the Secretary of State of the State of Delaware a Certificate of Amendment to the Certificate of Limited Partnership of the Partnership reflecting the admission of Crosstex Energy GP, LLC as the general partner of the Partnership. A copy of the Certificate of Amendment to the Certificate of Limited Partnership of the Partnership is filed as Exhibit 3.2 hereto and incorporated herein by reference.

Credit Agreement Amendment

On August 3, 2012, the Partnership entered into a Fifth Amendment to Amended and Restated Credit Agreement (the “Credit Agreement Amendment”), which amended that certain Amended and Restated Credit Agreement, dated as of February 10, 2010 (the “Credit Agreement”), by and among the Partnership, Bank of America, N.A., as Administrative Agent and L/C Issuer, and the other lenders party thereto, as amended by First Amendment to Amended and Restated Credit Agreement, dated as of May 2, 2011 (the “First Amendment”), Second Amendment to Amended and Restated Credit Agreement, dated as of July 11, 2011 (the “Second Amendment”), Third Amendment to Amended and Restated Credit Agreement, dated as of January 24, 2012 (the “Third Amendment”) and Fourth Amendment to Amended and Restated Credit Facility, dated as of May 23, 2012 (the “Fourth Amendment,” and, together with the Credit Agreement, the First Amendment, the Second Amendment, the Third Amendment and the Credit Agreement Amendment, the “Amended Credit Agreement”).

The Credit Agreement Amendment amends the Credit Agreement to require, on a semi-annual basis, the Partnership to deliver additional real property information to the administrative agent thereunder.

The description set forth above is qualified in its entirety by (i) the Credit Agreement, which is filed as Exhibit 10.1 to the Partnership’s Current Report on Form 8-K filed on February 16, 2010, (ii) the First Amendment, which is filed as Exhibit 10.1 to the Partnership’s Current Report on Form 8-K filed on May 3, 2011, (iii) the Second Amendment, which is filed as Exhibit 10.1 to the Partnership’s Current Report on Form 8-K filed on July 12, 2011, (iv) the Third Amendment, which is filed as Exhibit 10.1 to the Partnership’s Current Report on Form 8-K filed on January 25, 2012, (v) the Fourth Amendment, which is filed as Exhibit 10.1 to the Partnership’s Current Report on Form 8-K filed on May 24, 2012 and (vi) the Credit Agreement Amendment, a copy of which is filed as Exhibit 10.3 to this Quarterly Report on Form 10-Q and is incorporated herein by reference.

2018 Supplemental Indenture

On August 6, 2012, the Partnership, Crosstex Energy Finance Corporation (“FinCo” and, together with the Partnership, the “Issuers”), Clearfield Acquisition Corporation and Wells Fargo Bank, National Association, as trustee (the “Trustee”), entered into a Supplemental Indenture (the “2018 Supplemental Indenture”) to the Indenture, dated as of February 10, 2010 (the “2018 Indenture”), among the Issuers, certain subsidiary guarantors and the Trustee, which governs the 2018 Notes. The 2018 Supplemental Indenture amends the 2018 Indenture to add Clearfield Acquisition Corporation as a guarantor of the 2018 Notes in order to satisfy the Issuers’ obligation to add as a guarantor of the 2018 Notes certain subsidiaries of the Partnership that guarantee any other indebtedness of the Issuers. A copy of the 2018 Supplemental Indenture is filed as Exhibit 4.3 to this Quarterly Report on Form 10-Q.

The description set forth above is qualified in its entirety by (i) the 2018 Supplemental Indenture, which is filed as Exhibit 4.3 to this Quarterly Report on Form 10-Q and is incorporated herein by reference and (ii) the 2018 Indenture, which is filed as Exhibit 4.1 to the Partnership’s Current Report on Form 8-K filed on February 16, 2010.

2022 Supplemental Indenture

On August 6, 2012, the Issuers, Clearfield Acquisition Corporation and the Trustee entered into a Supplemental Indenture (the “2022 Supplemental Indenture”) to the Indenture, dated as of May 24, 2012 (the “2022 Indenture”), among the Issuers, certain subsidiary guarantors and the Trustee, which governs the 2022 Notes. The 2022 Supplemental Indenture amends the 2022 Indenture to add Clearfield Acquisition Corporation as a guarantor of the 2022 Notes in order to satisfy the Issuers’ obligation to add as a guarantor of the 2022 Notes certain subsidiaries of the Partnership that guarantee any other indebtedness of the Issuers. A copy of the 2022 Supplemental Indenture is filed as Exhibit 4.4 to this Quarterly Report on Form 10-Q.

The description set forth above is qualified in its entirety by (i) the 2022 Supplemental Indenture, which is filed as Exhibit 4.4 to this Quarterly Report on Form 10-Q and is incorporated herein by reference and (ii) the 2022 Indenture, which is filed as Exhibit 4.1 to the Partnership’s Current Report on Form 8-K filed on May 24, 2012.

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).
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.
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	—	Certificate of Limited Partnership of Crosstex Energy Services, L.P. (incorporated by reference to Exhibit 3.3 to our Registration Statement on Form S-1, file No. 333-97779).
3 .8	—	Second Amended and Restated Agreement of Limited Partnership of Crosstex Energy Services, L.P., dated as of April 1, 2004 (incorporated by reference to Exhibit 3.5 to our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004, file No. 000-50067).
3 .9	—	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 .10	—	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 .11	—	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).
4 .1	—	Indenture governing the Issuers' $7^{1}/_{8}$% senior unsecured notes due 2022, dated as of May 24, 2012, by and among Crosstex Energy, L.P., Crosstex Energy Finance Corporation, the Guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated May 23, 2012, filed with the Commission on May 24, 2012).

Number		Description
4 .2		Registration Rights Agreement, dated as of May 24, 2012, by and among Crosstex Energy, L.P., Crosstex Energy Finance Corporation, the Guarantors named therein and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as representative of the several Initial Purchasers named therein (incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K dated May 23, 2012, filed with the Commission on May 24, 2012).
4 .3*		Supplemental Indenture, dated as of August 6, 2012, to the indenture governing the Issuers' $8^{7}/_{8}$% senior unsecured notes due 2018, dated as of February 10, 2010, by and among Crosstex Energy, L.P., Crosstex Energy Finance Corporation, the Guarantors named therein and Wells Fargo Bank, National Association, as trustee.
4 .4*		Supplemental Indenture, dated as of August 6, 2012, to the indenture governing the Issuers' $7^{1}/_{8}$% senior unsecured notes due 2022, dated as of May 24, 2012, by and among Crosstex Energy, L.P., Crosstex Energy Finance Corporation, the Guarantors named therein and Wells Fargo Bank, National Association, as trustee.
10 .1		Fourth Amendment to Amended and Restated Credit Agreement, dated as of May 23, 2012, 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 May 23, 2012, filed with the Commission on May 24, 2012).
10 .2		Purchase Agreement, dated as of May 10, 2012, by and among Crosstex Energy, L.P., Crosstex Energy Finance Corporation, the Guarantors named therein and the Initial Purchasers named therein (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated May 9, 2012, filed with the Commission on May 11, 2012).
10 .3*		Fifth Amendment to Amended and Restated Credit Agreement, dated as of August 3, 2012, 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.
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 the Principal Financial Officer of the Company pursuant to 18 U.S.C. Section 1350.

* 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
Senior Vice President and Chief Financial Officer

August 7, 2012

Exhibit 3.2

CERTIFICATE OF AMENDMENT
TO THE
CERTIFICATE OF LIMITED PARTNERSHIP
OF
CROSSTEX ENERGY, L.P.

The undersigned, desiring to amend the Certificate of Limited Partnership of Crosstex Energy, L.P. pursuant to the provisions of Section 17-202 of the Revised Uniform Limited Partnership Act of the State of Delaware, does hereby certify as follows:

FIRST: The name of the limited partnership is Crosstex Energy, L.P.

SECOND: Article III of the Certificate of Limited Partnership shall be amended as follows:

III. The name and mailing address of the general partner are as follows:

Name	Mailing Address
Crosstex Energy GP, LLC	2501 Cedar Springs, Suite 600 Dallas, TX 75201

IN WITNESS WHEREOF, the undersigned has duly executed this Certificate of Amendment to the Certificate of Limited Partnership as of this 6th day of August, 2012.

GENERAL PARTNER:

CROSSTEX ENERGY GP, LLC,
its general partner

By: **/s/ Joe Davis**
Name: **Joe Davis**
Title: **Executive Vice President and General Counsel**

Exhibit 4.3

CROSSTEX ENERGY, L.P.

CROSSTEX ENERGY FINANCE CORPORATION

and

the Guarantor named herein

8.875% SENIOR NOTES DUE 2018

SUPPLEMENTAL INDENTURE
AND AMENDMENT — SUBSIDIARY GUARANTEE

DATED AS OF AUGUST 6, 2012

WELLS FARGO BANK, NATIONAL ASSOCIATION,

Trustee

This SUPPLEMENTAL INDENTURE, dated as of August 6, 2012 and effective as of June 25, 2012, is among Crosstex Energy, L.P., a Delaware limited partnership (the "Company"), Crosstex Energy Finance Corporation, a Delaware corporation ("Finance Corp." and, together with the Company, the "Issuers"), the party identified under the caption "Guarantor" on the signature page hereto (the "Guarantor"), and Wells Fargo Bank, National Association, a national banking association, as Trustee.

RECITALS

WHEREAS, the Issuers, the initial Guarantors and the Trustee entered into an Indenture, dated as of February 10, 2010 (the "Indenture"), pursuant to which the Company has issued $725,000,000 aggregate principal amount of 8.875% Senior Notes due 2018 (the "Notes");

WHEREAS, Section 9.01(g) of the Indenture provides that the Issuers, the Guarantors and the Trustee may amend or supplement the Indenture in order to comply with Section 4.13 or 10.03 thereof, without the consent of the Holders of the Notes; and

WHEREAS, all acts and things prescribed by the Indenture, by law and by the Certificate of Incorporation and the Bylaws (or comparable constituent documents) of the Issuers, of the Guarantor and of the Trustee necessary to make this Supplemental Indenture a valid instrument legally binding on the Issuers, the Guarantor and the Trustee, in accordance with its terms, have been duly done and performed;

NOW, THEREFORE, to comply with the provisions of the Indenture and in consideration of the above premises, the Issuers, the Guarantor and the Trustee covenant and agree for the equal and proportionate benefit of the respective Holders of the Notes as follows:

ARTICLE 1

Section 1.01. This Supplemental Indenture is supplemental to the Indenture and does and shall be deemed to form a part of, and shall be construed in connection with and as part of, the Indenture for any and all purposes.

Section 1.02. This Supplemental Indenture shall become effective immediately upon its execution and delivery by each of the Issuers, the Guarantor and the Trustee.

ARTICLE 2

From this date, in accordance with Section 4.13 or 10.03 and by executing this Supplemental Indenture, the Guarantor whose signature appears below is subject to the provisions of the Indenture to the extent provided for in Article 10 thereunder.

ARTICLE 3

Section 3.01. Except as specifically modified herein, the Indenture and the Notes are in all respects ratified and confirmed *(mutatis mutandis)* and shall remain in full force and effect in accordance with their terms with all capitalized terms used herein without definition having the same respective meanings ascribed to them as in the Indenture.

Section 3.02. Except as otherwise expressly provided herein, no duties, responsibilities or liabilities are assumed, or shall be construed to be assumed, by the Trustee by reason of this Supplemental Indenture. This Supplemental Indenture is executed and accepted by the Trustee subject to all the terms and conditions set forth in the Indenture with the same force and effect as if those terms and conditions were repeated at length herein and made applicable to the Trustee with respect hereto.

Section 3.03. THIS SUPPLEMENTAL INDENTURE SHALL BE GOVERNED BY, AND CONSTRUED IN ACCORDANCE WITH, THE LAWS OF THE

STATE OF NEW YORK.

Section 3.04. The parties may sign any number of copies of this Supplemental Indenture. Each signed copy shall be an original, but all of such executed copies together shall represent the same agreement.

[NEXT PAGE IS SIGNATURE PAGE]

IN WITNESS WHEREOF, the parties hereto have caused this Supplemental Indenture to be duly executed, all as of the date first written above.

CROSSTEX ENERGY, L.P.

BY: CROSSTEX ENERGY GP, LLC,
its general partner

By: /s/ Michael J. Garberding
Name: Michael J. Garberding
Title: Senior Vice President and Chief Financial Officer

CROSSTEX ENERGY FINANCE CORPORATION

By: /s/ Michael J. Garberding
Name: Michael J. Garberding
Title: Senior Vice President and Chief Financial Officer

GUARANTOR

CLEARFIELD ACQUISITION CORPORATION

By: /s/ Michael J. Garberding
Name: Michael J. Garberding
Title: Senior Vice President and Chief Financial Officer

WELLS FARGO BANK, NATIONAL ASSOCIATION,
as Trustee

By: /s/ John C. Stohlmann
Name: John C. Stohlmann
Title: Vice President

CROSSTEX ENERGY, L.P.

CROSSTEX ENERGY FINANCE CORPORATION

and

the Guarantor named herein

$7^{1}/_{8}$% SENIOR NOTES DUE 2022

SUPPLEMENTAL INDENTURE
AND AMENDMENT — SUBSIDIARY GUARANTEE

DATED AS OF AUGUST 6, 2012

WELLS FARGO BANK, NATIONAL ASSOCIATION,

Trustee

This SUPPLEMENTAL INDENTURE, dated as of August 6, 2012 and effective as of June 25, 2012, is among Crosstex Energy, L.P., a Delaware limited partnership (the "Company"), Crosstex Energy Finance Corporation, a Delaware corporation ("Finance Corp." and, together with the Company, the "Issuers"), the party identified under the caption "Guarantor" on the signature page hereto (the "Guarantor"), and Wells Fargo Bank, National Association, a national banking association, as Trustee.

RECITALS

WHEREAS, the Issuers, the initial Guarantors and the Trustee entered into an Indenture, dated as of May 24, 2012 (the "Indenture"), pursuant to which the Company has issued $250,000,000 aggregate principal amount of $7^{1}/_{8}$% Senior Notes due 2022 (the "Notes");

WHEREAS, Section 9.01(g) of the Indenture provides that the Issuers, the Guarantors and the Trustee may amend or supplement the Indenture in order to comply with Section 4.13 or 10.02 thereof, without the consent of the Holders of the Notes; and

WHEREAS, all acts and things prescribed by the Indenture, by law and by the Certificate of Incorporation and the Bylaws (or comparable constituent documents) of the Issuers, of the Guarantor and of the Trustee necessary to make this Supplemental Indenture a valid instrument legally binding on the Issuers, the Guarantor and the Trustee, in accordance with its terms, have been duly done and performed;

NOW, THEREFORE, to comply with the provisions of the Indenture and in consideration of the above premises, the Issuers, the Guarantor and the Trustee covenant and agree for the equal and proportionate benefit of the respective Holders of the Notes as follows:

ARTICLE 1

Section 1.01. This Supplemental Indenture is supplemental to the Indenture and does and shall be deemed to form a part of, and shall be construed in connection with and as part of, the Indenture for any and all purposes.

Section 1.02. This Supplemental Indenture shall become effective immediately upon its execution and delivery by each of the Issuers, the Guarantor and the Trustee.

ARTICLE 2

From this date, in accordance with Section 4.13 or 10.02 and by executing this Supplemental Indenture, the Guarantor whose signature appears below is subject to the provisions of the Indenture to the extent provided for in Article 10 thereunder.

ARTICLE 3

Section 3.01. Except as specifically modified herein, the Indenture and the Notes are in all respects ratified and confirmed*(mutatis mutandis)* and shall remain in full force and effect in accordance with their terms with all capitalized terms used herein without definition having the same respective meanings ascribed to them as in the Indenture.

Section 3.02. Except as otherwise expressly provided herein, no duties, responsibilities or liabilities are assumed, or shall be construed to be assumed, by the Trustee by reason of this Supplemental Indenture. This Supplemental Indenture is executed and accepted by the Trustee subject to all the terms and conditions set forth in the Indenture with the same force and effect as if those terms and conditions were repeated at length herein and made applicable to the Trustee with respect hereto.

Section 3.03. THIS SUPPLEMENTAL INDENTURE SHALL BE GOVERNED BY, AND CONSTRUED IN ACCORDANCE WITH, THE LAWS OF THE

STATE OF NEW YORK.

Section 3.04. The parties may sign any number of copies of this Supplemental Indenture. Each signed copy shall be an original, but all of such executed copies together shall represent the same agreement.

[NEXT PAGE IS SIGNATURE PAGE]

IN WITNESS WHEREOF, the parties hereto have caused this Supplemental Indenture to be duly executed, all as of the date first written above.

CROSSTEX ENERGY, L.P.

BY: CROSSTEX ENERGY GP, LLC,
its general partner

By: /s/ Michael J. Garberding
Name: Michael J. Garberding
Title: Senior Vice President and Chief Financial Officer

CROSSTEX ENERGY FINANCE CORPORATION

By: /s/ Michael J. Garberding
Name: Michael J. Garberding
Title: Senior Vice President and Chief Financial Officer

GUARANTOR

CLEARFIELD ACQUISITION CORPORATION

By: /s/ Michael J. Garberding
Name: Michael J. Garberding
Title: Senior Vice President and Chief Financial Officer

WELLS FARGO BANK, NATIONAL ASSOCIATION,
as Trustee

By: /s/ John C. Stohlmann
Name: John C. Stohlmann
Title: Vice President

Exhibit 10.3

Execution Version

FIFTH AMENDMENT TO AMENDED AND RESTATED CREDIT AGREEMENT

THIS FIFTH AMENDMENT TO AMENDED AND RESTATED CREDIT AGREEMENT (this "Amendment") is entered into as of August 3, 2012 by and among each of the persons listed on the signature pages hereto as lenders (the "Lenders"), Crosstex Energy, L.P., a Delaware limited partnership (the "Borrower"), and Bank of America, N.A., as administrative agent (in such capacity, the "Administrative Agent") and L/C Issuer.

ARTICLE I

BACKGROUND

A. The Lenders, the Administrative Agent, the L/C Issuer and the Borrower are parties to that certain Amended and Restated Credit Agreement dated as of February 10, 2010 (as amended, supplemented or restated, the "Credit Agreement"). Terms defined in the Credit Agreement and not otherwise defined herein have the same meanings when used herein.

B. The Borrower has requested, and the Lenders have agreed to amend the Credit Agreement as provided for herein and on the terms and conditions set forth herein.

ARTICLE II

AGREEMENT

NOW THEREFORE, in consideration of the covenants, conditions and agreements hereinafter set forth, and for other good and valuable consideration, the receipt and adequacy of which are all hereby acknowledged, the parties hereto covenant and agree as follows:

Section 1. Amendments to the Credit Agreement. The Credit Agreement is hereby amended as follows:

(a) Section 6.02(f) of the Credit Agreement is restated in its entirety to read as follows:

"(f) promptly, and in any event within 60 days after June 30 and December 31 of each year, commencing with the period ended June 30, 2012, a summary of (1) substantially all new real property interests (including owned and leased properties, easements and other property interests) acquired and/or recorded by the Borrower or any Subsidiary and (2) any previously acquired property that is not encumbered by a Mortgage, that has been developed by the Borrower or any Subsidiary, on which pipelines or other assets of Borrower or any Subsidiary are located, or which has become subject to a plan for development or construction, in each case during the preceding six month period ending on such June 30

or December 31, as applicable (collectively, a "Newly Acquired Real Property Report");"

Section 2. Conditions Precedent. This Amendment shall become effective as of the date first set forth above upon the satisfaction of the following conditions precedent:

(a) The Administrative Agent shall have received each of the following:

(1) this Amendment, duly executed by the Borrower, the Required Lenders, and the Administrative Agent;

(2) the acknowledgment attached to this Amendment, duly executed by each Guarantor;

(3) payment or evidence of payment of all reasonable fees and expenses owed by the Borrower to the Administrative Agent including, without limitation, the reasonable fees and expenses of Bracewell & Giuliani LLP, counsel to the Administrative Agent; and

(4) such other documents, instruments and certificates as reasonably requested by the Administrative Agent and the Lenders.

(b) The representations and warranties set forth in Section 3 of this Amendment shall be true and correct on and as of the date hereof.

Section 3. Representations and Warranties.

(a) The Borrower represents and warrants to the Lenders and the Administrative Agent as set forth below:

(1) The Borrower (a) is duly organized or formed, validly existing and, as applicable, in good standing under the Laws of the jurisdiction of its incorporation or organization, and (b) has all requisite power and authority and all requisite governmental licenses, authorizations, consents and approvals to execute, deliver and perform its obligations under this Amendment.

(2) The execution, delivery and performance by the Borrower of this Amendment have been duly authorized by all necessary corporate or other organizational action, and do not and will not (a) contravene the terms of any of the Borrower's Organization Documents; (b) conflict with or result in any breach or contravention of, or the creation of any Lien under (other than Liens created under the Loan Documents), or require any payment to be made (other than payments required under any Loan Document) under (i) any Contractual Obligation to which the Borrower is a party or affecting the Borrower or its properties or any of its Subsidiaries or (ii) any order, injunction, writ or decree of any Governmental Authority or any arbitral award to which the Borrower or its property is subject; or (c) violate any Law; except in each case referred to in

clause (b), to the extent that such conflict, breach, contravention or violation could not reasonably be expected to have a Material Adverse Effect.

(3) No approval, consent, exemption, authorization, or other action by, or notice to, or filing with, any Governmental Authority or any other Person is necessary or required in connection with the execution, delivery or performance by, or enforcement against, the Borrower of this Amendment,

except for such approvals, consents, exemptions, authorizations, other actions, notices and filings as have been obtained, taken, given or made and are in full force and effect and with which the Borrower and its Subsidiaries are in compliance in all material respects or which the failure to have would not result in a Material Adverse Effect.

(4) This Amendment has been duly executed and delivered by the Borrower and acknowledged by each Guarantor. This Amendment constitutes the legal, valid and binding obligation of the Borrower, enforceable against it in accordance with its terms, except as the enforceability thereof may be limited by bankruptcy, insolvency, moratorium, reorganization or other similar laws affecting creditors' rights generally or by general principles of equity (regardless of whether such enforceability is considered in any proceeding in law or in equity).

(5) The execution, delivery and performance of this Amendment do not adversely affect the enforceability of any Lien of the Collateral Documents.

(6) Except as disclosed in Schedule 5.06 to the Credit Agreement, there is no pending or, to the knowledge of the Borrower, threatened action or proceeding affecting the Borrower or any Subsidiary before any Governmental Authority, referee or arbitrator that could reasonably be expected to have a Material Adverse Effect.

(7) The representations and warranties made by the Borrower and the Guarantors contained in Article V of the Credit Agreement and in each of the other Loan Documents are true and correct in all material respects on and as of the date hereof, as though made on and as of such date, other than any such representations or warranties that, by the their terms, refer to a specific date, in which case such representation or warranties are true and correct in all material respects as of such earlier specific date.

(8) No event has occurred and is continuing, or would result from the effectiveness of this Amendment, which constitutes a Default.

(9) As of June 30, 2012, the Borrower has no (a) Material Subsidiaries other than those listed on Schedule 3(a) and (b) non-Material Subsidiaries other than those listed on Schedule 3(b).

Section 4. Reference to and Effect on the Credit Agreement.

(a) On and after the effective date of this Amendment each reference in the Credit Agreement to "this Agreement," "hereunder," "hereof," "herein" or words of like import shall mean and be a reference to the Credit Agreement as amended by this Amendment, and each reference in the other Loan Documents to "the Credit Agreement," "thereunder," "thereof," "therein" or words of like import referring to the Credit Agreement, shall mean and be a reference to the Credit Agreement as amended by this Amendment.

(b) Except as specifically amended above, the Credit Agreement and the other Loan Documents shall remain in full force and effect and are hereby ratified and confirmed. Without limiting the generality of the foregoing, the Collateral Documents and all of the Collateral described therein do and shall continue to secure the payment of all obligations stated to be secured thereby under the Loan Documents.

(c) Except as expressly set forth herein, the execution, delivery and effectiveness of this Amendment shall not operate as a waiver of any right, power or remedy of the Administrative Agent or any Lender under any of the Loan Documents or constitute a waiver of any provision of any of the Loan Documents.

Section 5. Execution in Counterparts. This Amendment may be executed in any number of counterparts and by the parties hereto in separate counterparts, each which when so executed and delivered shall be deemed to be an original and all of which when taken together shall constitute but one and the same instrument. Delivery of an executed counterpart of a signature page to this Amendment by telecopier or other electronic imaging means shall be effective as delivery of an originally executed counterpart of this Amendment.

Section 6. Governing Law; Binding Effect. This Amendment shall be governed by, and construed and enforced in accordance with, the laws of the State of New York, and shall be binding upon the Borrower, the Administrative Agent, the L/C Issuer, each Lender and their respective successors and assigns.

Section 7. Costs and Expenses. The Borrower agrees to pay on demand all reasonable out-of-pocket costs and expenses of the Administrative Agent in connection with the preparation, execution and delivery of this Amendment and the other instruments and documents to be delivered hereunder, including the reasonable fees and out-of-pocket expenses of counsel for the Administrative Agent with respect thereto and with respect to advising the Administrative Agent as to its rights and responsibilities hereunder and thereunder.

THIS WRITTEN AMENDMENT AND THE LOAN DOCUMENTS REPRESENT THE FINAL AGREEMENT AMONG THE PARTIES AND MAY NOT BE CONTRADICTED BY EVIDENCE OF PRIOR, CONTEMPORANEOUS, OR SUBSEQUENT ORAL AGREEMENTS OF THE PARTIES.

THERE ARE NO UNWRITTEN ORAL AGREEMENTS BETWEEN THE PARTIES.

[Remainder of this page blank; signature pages follow]

Executed as of the date first set forth above.

CROSSTEX ENERGY, L.P.

By: Crosstex Energy GP, LLC,
its general partner

By: /s/ Michael J. Garberding
Name: Michael J. Garberding
Title: Senior Vice President and Chief Financial Officer

Each of the undersigned, as guarantors under the Amended and Restated Guaranty dated as of February 10, 2010 (as supplemented to date, the "Guaranty"), and as debtors, mortgagors, and/or grantors under the Collateral Documents, hereby (a) consents to this Amendment, and (b) confirms and agrees that the Guaranty and each of the Collateral Documents to which it is a party is and shall continue to be in full force and effect and is ratified and confirmed in all respects, except that, on and after the effective date of the Amendment each reference in the Guaranty and the other Collateral Documents to "the Credit Agreement," "thereunder," "thereof," "therein" or any other expression of like import referring to the Credit Agreement shall mean and be a reference to the Credit Agreement as modified by this Amendment.

ADDRESS FOR ALL UNDERSIGNED:

2501 Cedar Springs
Suite 100
Dallas, Texas 75201
Attention: General Counsel

CROSSTEX ENERGY SERVICES, L.P.

By: Crosstex Operating GP, LLC,
its general partner

By: /s/ Michael J. Garberding
Name: Michael J. Garberding
Title: Senior Vice President and Chief Financial Officer

CLEARFIELD ACQUISITION CORPORATION
CROSSTEX OPERATING GP, LLC
CROSSTEX ENERGY SERVICES GP, LLC
CROSSTEX LIG, LLC
CROSSTEX TUSCALOOSA, LLC
CROSSTEX LIG LIQUIDS, LLC
CROSSTEX PROCESSING SERVICES, LLC
CROSSTEX PELICAN, LLC
CROSSTEX PERMIAN, LLC
CROSSTEX PERMIAN II, LLC

By: /s/ Michael J. Garberding
Name: Michael J. Garberding
Title: Senior Vice President and Chief Financial Officer

CROSSTEX GULF COAST MARKETING LTD.
CROSSTEX CCNG PROCESSING LTD.
CROSSTEX NORTH TEXAS PIPELINE, L.P.
CROSSTEX NORTH TEXAS GATHERING, L.P.
CROSSTEX NGL MARKETING, L.P.
CROSSTEX NGL PIPELINE, L.P.

By: Crosstex Energy Services GP, LLC,
general partner of each above limited partnership

By: /s/ Michael J. Garberding
Name: Michael J. Garberding
Title: Senior Vice President and Chief Financial Officer

SABINE PASS PLANT FACILITY JOINT VENTURE

By: Crosstex Processing Services, LLC,
as general partner, and
By: Crosstex Pelican, LLC,
as general partner

By: /s/ Michael J. Garberding
Name: Michael J. Garberding
Title: Senior Vice President and Chief Financial Officer

BANK OF AMERICA, N.A.,
as Administrative Agent,
a Lender and L/C Issuer

By: /s/ Jeffrey H. Rathkamp
Name: Jeffrey H. Rathkamp
Title: Managing Director

Signature Page to Fifth Amendment to Amended and Restated Credit Agreement

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BNP PARIBAS

By: ______________________
Name:
Title:

By: ______________________
Name:
Title:

Signature Page to Fifth Amendment to Amended and Restated Credit Agreement

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COMERICA BANK

By: /s/ David P. Cagle
Name: David P. Cagle
Title: Senior Vice President

Signature Page to Fifth Amendment to Amended and Restated Credit Agreement

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COMPASS BANK

By: /s/ Blake Kirshman
Name: Blake Kirshman
Title: Assistant Vice President

Signature Page to Fifth Amendment to Amended and Restated Credit Agreement

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ROYAL BANK OF CANADA

By: /s/ Jason S. York
Name: Jason S. York
Title: Authorized Signatory

Signature Page to Fifth Amendment to Amended and Restated Credit Agreement

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SUMITOMO MITSUI BANKING CORP., NEW YORK

By: /s/ Kazuhisa Matsuda
Name: Kazuhisa Matsuda
Title: Managing Director

Signature Page to Fifth Amendment to Amended and Restated Credit Agreement

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U.S. BANK NATIONAL ASSOCIATION

By: /s/ Daniel K. Hansen
Name: Daniel K. Hansen
Title: Vice President

Signature Page to Fifth Amendment to Amended and Restated Credit Agreement

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WELLS FARGO BANK, N.A.

By: /s/ Andrew Ostrov
Name: Andrew Ostrov
Title: Director

Signature Page to Fifth Amendment to Amended and Restated Credit Agreement

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BANK OF MONTREAL

By: /s/ Gumaro Tijerina
Name: Gumaro Tijerina
Title: Director

Signature Page to Fifth Amendment to Amended and Restated Credit Agreement

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CAPITAL ONE, NATIONAL ASSOCIATION

By: /s/ Nancy Mak
Name: Nancy Mak
Title: Vice President

Signature Page to Fifth Amendment to Amended and Restated Credit Agreement

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GOLDMAN SACHS BANK USA

By: /s/ Michelle Latzoni
Name: Michelle Latzoni
Title: Authorized Signatory

Signature Page to Fifth Amendment to Amended and Restated Credit Agreement

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MORGAN STANLEY BANK, N.A.

By: /s/ William Jones
Name: William Jones
Title: Authorized Signatory

Signature Page to Fifth Amendment to Amended and Restated Credit Agreement

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CITIBANK, N.A.

By: /s/ John F. Miller
Name: John F. Miller
Title: Attorney-in-Fact

Signature Page to Fifth Amendment to Amended and Restated Credit Agreement

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ABN AMRO CAPITAL USA LLC

By: /s/ Darrell Holley
Name: Darrell Holley
Title: Managing Director

By: /s/ Casey Lowary
Name: Casey Lowary
Title: Director

Signature Page to Fifth Amendment to Amended and Restated Credit Agreement

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REGIONS BANK

By: /s/ Kelly L. Elmore III
Name: Kelly L. Elmore III
Title: Senior Vice President

Signature Page to Fifth Amendment to Amended and Restated Credit Agreement

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AMEGY BANK NATIONAL ASSOCIATION

By: /s/ Jill McSorley
Name: Jill McSorley
Title: Senior Vice President

Signature Page to Fifth Amendment to Amended and Restated Credit Agreement

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ONEWEST BANK, FSB

By: /s/ Sean M. Murphy
Name: Sean M. Murphy
Title: Senior Vice President

Signature Page to Fifth Amendment to Amended and Restated Credit Agreement

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SCHEDULE 3(a)

MATERIAL SUBSIDIARIES

Crosstex Energy Services, L.P. (DE)
Crosstex Operating GP, LLC (DE)*
Crosstex Energy Services GP, LLC (DE)*
Crosstex LIG, LLC (LA)
Crosstex Tuscaloosa, LLC (LA)*
Crosstex LIG Liquids, LLC (LA)
Crosstex Gulf Coast Marketing Ltd. (TX)*

Crosstex CCNG Processing Ltd. (TX)
Crosstex North Texas Pipeline, L.P. (TX)
Crosstex North Texas Gathering, L.P. (TX)
Crosstex NGL Pipeline, L.P. (TX)*
Crosstex NGL Marketing, L.P. (TX)*
Crosstex Processing Services, LLC (DE)
Crosstex Pelican, LLC (DE)
Sabine Pass Plant Facility Joint Venture (TX)*
Crosstex Permian, LLC (TX)*
Crosstex Permian II, LLC (TX)*
Crosstex Louisiana Gathering, LLC (Louisiana)*
Clearfield Acquisition Corporation (DE)*

*Indicates entity has previously been treated as a Material Subsidiary (e.g., it pledged assets and is a Guarantor) but does not technically meet the definition of a "Material Subsidiary" as of June 30, 2012.

SCHEDULE 3(b)

NON-MATERIAL SUBSIDIARIES

Crosstex Louisiana Energy, L.P. (Delaware)
Crosstex DC Gathering Company, J.V. (Texas)
Crosstex Energy Finance Corporation (Delaware)

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: August 7, 2012

Exhibit 31.2

CERTIFICATIONS

I, Michael J. Garberding, Senior 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,
Senior Vice President and Chief Financial Officer
(principal financial and accounting officer)

Date: August 7, 2012

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 June 30, 2012 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

August 7, 2012

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

August 7, 2012

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.