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

Form 10-Q

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

For the quarterly period ended September 30, 2009

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 the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ 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 Exchange Act).
Yes ☐ No ☑

As of October 30, 2009, the Registrant had 49,110,166 common units outstanding.

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CROSSTEX ENERGY, L.P.

Condensed Consolidated Balance Sheets

	September 30, 2009	December 31, 2008
	(Unaudited)	
	(In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 905	$ 1,636
Accounts and notes receivable, net:		
Trade, accrued revenue and other	168,452	353,364
Related party	17	110
Fair value of derivative assets	10,422	27,166
Natural gas and natural gas liquids, prepaid expenses and other	11,295	9,645
Total current assets	191,091	391,921
Assets held for sale	183,528	¾
Property and equipment, net of accumulated depreciation of $239,186 and $296,393, respectively	1,238,510	1,527,280
Fair value of derivative assets	8,701	4,628
Intangible assets, net of accumulated amortization of $106,422 and $89,231, respectively	544,288	578,096
Goodwill	¾	19,673
Other assets, net	13,129	11,668
Total assets	$ 2,179,247	$ 2,533,266
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable, drafts payable and accrued gas purchases	$ 127,723	$ 322,722
Fair value of derivative liabilities	24,561	28,506
Current portion of long-term debt	21,279	9,412
Other current liabilities	50,627	64,191
Total current liabilities	224,190	424,831
Liabilities of assets held for sale	9,419	¾
Long-term debt	1,064,403	1,254,294
Obligations under capital lease	21,327	24,708
Deferred tax liability	8,184	8,727
Fair value of derivative liabilities	17,879	22,775
Commitments and contingencies	¾	¾
Partners' equity including non-controlling interest	833,845	797,931
Total liabilities and equity	$ 2,179,247	$ 2,533,266

See accompanying notes to condensed consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Operations

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(Unaudited) (In thousands, except per unit amounts)			
Revenues:				
Midstream	$ 349,194	$ 854,335	$ 1,049,451	$ 2,650,121
Profit on energy trading activities	1,504	647	3,645	2,331
Total revenues	350,698	854,982	1,053,096	2,652,452
Operating costs and expenses:				
Purchased gas	269,461	775,782	824,812	2,411,025
Operating expenses	29,027	34,409	84,733	93,695
General and administrative	16,051	16,103	43,617	47,983
Gain on sale of property	(356)	(4)	(899)	(1,023)
Gain on derivatives	(1,672)	(2,460)	(6,723)	(4,286)
Depreciation and amortization	31,155	26,905	90,824	79,189
Total operating costs and expenses	343,666	850,735	1,036,364	2,626,583
Operating income	7,032	4,247	16,732	25,869
Other income (expense):				
Interest expense, net	(26,555)	(14,210)	(64,832)	(32,828)
Loss on extinguishment of debt	¾	¾	(4,669)	¾
Other income	570	113	736	7,670
Total other income (expense)	(25,985)	(14,097)	(68,765)	(25,158)
Income (loss) from continuing operations before non-controlling interest and income taxes	(18,953)	(9,850)	(52,033)	711
Income tax provision	(369)	(1,576)	(1,244)	(2,055)
Loss from continuing operations, net of tax	(19,322)	(11,426)	(53,277)	(1,344)
Income (loss) from discontinued operations, net of tax	(3,962)	6,227	4,378	21,792
Gain from sale of discontinued operations, net of tax	97,423	¾	97,423	¾
Net income (loss)	74,139	(5,199)	48,524	20,448
Less: Net income (loss) from continuing operations attributable to the non-controlling interest	(50)	44	(9)	238
Net income (loss) attributable to Crosstex Energy, L.P.	$ 74,189	$ (5,243)	$ 48,533	$ 20,210
General partner interest in net income (loss) including incentive distribution rights	$ 681	$ 5,810	$ (1,210)	$ 27,861
Limited partners' interest in net income (loss) attributable to Crosstex Energy, L.P.	$ 73,508	$ (11,053)	$ 49,743	$ (7,651)
Net income (loss) attributable to Crosstex Energy, L.P. per limited partners' unit:				
Basic common unit	$ 1.46	$ (0.24)	$ 0.32	$ (3.06)
Diluted common unit	$ 1.44	$ (0.24)	$ 0.31	$ (3.06)
Basic and diluted senior subordinated series C unit (see Note 5(c))	$ ¾	$ ¾	$ ¾	$ 9.44
Basic and diluted senior subordinated series D unit (see Note 5(c))	$ ¾	$ ¾	$ 8.85	$ ¾

See accompanying notes to condensed consolidated financial statements.

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CROSSTEX ENERGY, L.P.

Consolidated Statements of Changes in Partners' Equity
Nine Months Ended September 30, 2009

	Common Units		Subordinated D Units		General Partner Interest		Accumulated Other Comprehensive Income	Non-Controlling Interest	Total
	$	Units	$	Units	$	Units			
					(Unaudited) (In thousands)				
Balance, December 31, 2008	$ 674,564	44,909	$ 99,942	3,875	$ 16,805	996	$ 3,110	$ 3,510	$ 797,931
Conversion of subordinated units (1)	99,942	4,069	(99,942)	(3,875)	¾	¾	¾	¾	¾
Conversion of restricted units for common units, net of units withheld for taxes	(134)	132	¾	¾	¾	¾	¾	¾	(134)
Capital contributions	¾	¾	¾	¾	14	6	¾	¾	14
Stock-based compensation	3,970	¾	¾	¾	2,306	¾	¾	¾	6,276
Distributions	(11,368)	¾	¾	¾	(229)	¾	¾	¾	(11,597)
Net income (loss)	49,743	¾	¾	¾	(1,210)	¾	¾	(9)	48,524
Hedging gains or losses reclassified to earnings	¾	¾	¾	¾	¾	¾	(5,688)	¾	(5,688)
Adjustment in fair value of derivatives	¾	¾	¾	¾	¾	¾	(1,165)	¾	(1,165)
Distribution to non-controlling interest	¾	¾	¾	¾	¾	¾	¾	(316)	(316)
Balance, September 30, 2009	$ 816,717	49,110	$ ¾	¾	$ 17,686	1,002	$ (3,743)	$ 3,185	$ 833,845

(1) Converted at 1.05 common units for 1.00 senior subordinated series D unit.

See accompanying notes to condensed consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Comprehensive Income

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
	(Unaudited) (In thousands)			
Net income (loss)	$ 74,139	$ (5,199)	$ 48,524	$ 20,448
Hedging gains reclassified to earnings	171	8,603	(5,688)	20,186
Adjustment in fair value of derivatives	99	20,363	(1,165)	(9,916)
Comprehensive income (loss)	74,409	23,767	41,671	30,718
Comprehensive income (loss) attributable to non-controlling interest	(50)	44	(9)	238
Comprehensive income (loss) attributable to Crosstex Energy, L.P.	$ 74,459	$ 23,723	$ 41,680	$ 30,480

See accompanying notes to condensed consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Cash Flows

	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
	(Unaudited) (In thousands)	
Cash flows from operating activities:		
Net income	$ 48,524	$ 20,448
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	101,474	98,640
Gain on sale of property	(98,361)	(1,591)
Deferred tax (benefit) expense	(543)	298
Non-cash stock-based compensation	6,276	8,250
Non-cash derivatives gain	(3,021)	(2,216)
Non-cash loss on debt extinguishment	4,669	¾
Interest paid-in-kind	6,042	¾
Amortization of debt issue costs	7,654	2,055
Changes in assets and liabilities:		
Accounts receivable, accrued revenue, and other	168,187	38,479
Natural gas and natural gas liquids, prepaid expenses and other	(1,766)	(4,732)
Accounts payable, accrued gas purchases and other accrued liabilities	(176,440)	57,984
Net cash provided by operating activities	62,695	217,615
Cash flows from investing activities:		
Additions to property and equipment	(90,793)	(218,268)
Insurance recoveries on property and equipment	9,687	¾
Proceeds from sale of property	245,276	3,775
Net cash provided (used) by investing activities	164,170	(214,493)
Cash flows from financing activities:		
Proceeds from borrowings	489,943	1,357,260
Payments on borrowings	(673,470)	(1,245,508)
Proceeds from capital lease obligations	1,486	18,348
Payments on capital lease obligations	(1,867)	(789)
Decrease in drafts payable	(17,871)	(28,931)
Debt refinancing costs	(13,784)	(369)
Conversion of restricted units, net of units withheld for taxes	(134)	(1,373)
Distributions to non-controlling interest	(316)	¾
Distributions to partners	(11,597)	(107,996)
Proceeds from exercise of unit options	¾	729
Net proceeds from common unit offering	¾	99,928
Contributions from general partner	14	2,183
Contributions from non-controlling interest	¾	109
Net cash provided (used) by financing activities	(227,596)	93,591
Net increase (decrease) in cash and cash equivalents	(731)	96,713
Cash and cash equivalents, beginning of period	1,636	142
Cash and cash equivalents, end of period	$ 905	$ 96,855
Cash paid for interest	$ 64,985	$ 55,636
Cash paid for income taxes	$ 1,387	$ 1,229

See accompanying notes to condensed consolidated financial statements.

CROSSTEX ENERGY, L.P.

Notes To Condensed Consolidated Financial Statements — (Continued)
September 30, 2009
(Unaudited)

(1) General

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

Crosstex Energy, L.P., a Delaware limited partnership formed on July 12, 2002, is engaged in the gathering, transmission, processing and marketing of natural gas and natural gas liquids (NGLs). 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. 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.

Crosstex Energy GP, L.P. is the general partner of the Partnership. Crosstex Energy GP, L.P., is an indirect, wholly-owned subsidiary of Crosstex Energy, Inc. (CEI).

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 years 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, 2008.

(a) Management's Use of Estimates

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) Recent Accounting Pronouncements

Financial Accounting Standards Board Accounting Standards Codification (FASB ASC) 805 and FASB ASC 810-10-65-1 were issued December 2007. FASB ASC 805 requires most identifiable assets, liabilities, non-controlling interests and goodwill acquired in a business combination to be recorded at "full fair value." The Statement applies to all business combinations, including combinations among mutual entities and combinations by contract alone. Under FASB ASC 805 all business combinations will be accounted for by applying the acquisition method. FASB ASC 805 is effective for periods beginning on or after December 15, 2008. FASB ASC 810-10-65-1 requires non-controlling interests (previously referred to as minority interests) to be treated as a separate component of equity, not as a liability or other item outside of permanent equity. FASB ASC 810-10-65-1 was adopted January 1, 2009 and comparative period information has been recast to classify non-controlling interests in equity, and attribute net income and other comprehensive income to non-controlling interests.

FASB ASC 815-10-65-1 was issued March 2008 and requires entities to provide greater transparency about how and why the entity uses derivative instruments, how the instruments and related hedged items are accounted for under FASB ASC 815 and how the instruments and related hedged items affect the financial position, results of operations and cash flows of the entity. FASB ASC 815-10-65-1 is effective for fiscal years beginning after November 15, 2008. FASB ASC 815-10-65-1 was adopted effective January 1, 2009. Required disclosures were added to Note 7.

FASB ASC 105 was released July 1, 2009 and intended to improve financial reporting by identifying a consistent framework, or hierarchy, for selecting accounting principles to be used in preparing financial statements of non-governmental entities that are presented in conformity with generally accepted accounting principles (GAAP) in the United States of America. SFAS No. 162 has been superseded by SFAS No. 168, "*The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles"* (the Codification) released July 1, 2009. The Codification became the exclusive authoritative reference for non-governmental U.S. GAAP for use in financial statements issued for interim and annual periods ending after September 15, 2009, except for Securities and Exchange Commission (SEC) rules and interpretive releases, which are also authoritative GAAP for SEC registrants. The change establishes non-governmental U.S. GAAP into the authoritative Codification and guidance that is non-authoritative. The contents of the Codification carry the same level of authority, eliminating the four-level GAAP hierarchy previously set forth in Statement 162. The Codification supersedes all existing non-SEC accounting and reporting standards. All other non-grandfathered, non-SEC accounting literature not included in the Codification has become non-authoritative. The Partnership has revised all GAAP references to reflect the Codification for the quarter ending September 30, 2009.

FASB ASC 260-10-45-60 was issued in June 2008 and requires unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents to be treated as *participating securities* as defined in FASB ASC 260-10-20 and, therefore, included in the earnings allocation in computing earnings per share under the two-class method described in FASB ASC 260. FASB ASC 260-10-45-60 is effective for financial statements issued for fiscal years beginning after December 15, 2008 and interim periods within those years. The Partnership adopted FASB ASC 260-10-45-60 effective January 1, 2009 and adjusted all prior reporting periods to conform to the requirements.

In addition, FASB ASC 260-10-55-102 addresses the consensus reached by the Task Force that incentive distribution rights (IDRs) in a typical master limited partnership are participating securities under FASB ASC 260, but earnings in excess of the partnership's "available cash" should not be allocated to the IDR holders for purposes of calculating earnings-per-share using the two-class method when "available cash" represents a specified threshold that limits participation. The consensus only applies when payments to IDR holders are accounted for as equity distributions. The consensus is effective for fiscal years beginning after December 15, 2008 and applied retrospectively to all periods presented. Under the Partnership's partnership agreement, "available cash" is a specified threshold that limits participation for IDR holders. Therefore earnings in excess of the Partnership's "available cash" during the three and nine months ended September 30, 2009 were not allocated to IDR holders.

In June 2009 FASB ASC 810-10-05-8 was issued. It requires reporting entities to evaluate former Qualifying Special Purpose Entities or QSPEs for consolidation, changes the approach to determining a variable interest entity's (VIE) primary beneficiary from a quantitative assessment to a qualitative assessment designed to identify a controlling financial interest, and increases the frequency of required reassessments to determine whether a company is the primary beneficiary of a VIE. It also clarifies, but does not significantly change, the characteristics that identify a VIE. This statement requires additional year-end and interim disclosures for public and nonpublic companies that are similar to the disclosures required by FASB ASC 860-10-65-2. The statement is effective for fiscal years beginning after November 15, 2009 and for subsequent interim and annual reporting periods. The Partnership does not expect this statement to have a significant impact to its financial statements.

FASB ASC 855 was issued June 2009 and is effective for interim or annual financial periods ending after June 15, 2009 and addresses accounting and disclosure requirements related to subsequent events. The statement requires management to evaluate subsequent events through the date the financial statements are issued. Companies are required to disclose the date through which subsequent events have been evaluated. The Partnership has taken this statement into consideration in Note 12.

FASB ASC 825-10-65-1 requires publicly traded companies to disclose the fair value of financial instruments within the scope of FASB ASC 825 in interim financial statements, adding to the current requirement to make those disclosures in annual financial statements. FASB ASC 825-10-65-1 is effective for interim and annual periods ending after June 15, 2009. The Partnership has added the required footnote disclosure in Note 9.

(2) Assets Held for Disposition

During 2009, the Partnership has sold certain non-strategic assets and used the proceeds from such sales to reduce long-term indebtedness.

The Partnership sold the Arkoma system in the first quarter 2009 to an unrelated third party for approximately $10.7 million. The asset had been impaired by $2.6 million in December 2008 to its fair value in anticipation of a first quarter disposition. The related loss on the sale recorded during the nine months ended September 30, 2009 was $0.3 million.

CROSSTEX ENERGY, L.P.

Notes To Condensed Consolidated Financial Statements — (Continued)

In addition to the sale of the Arkoma system, the Partnership entered into an agreement in May 2009 to sell its Midstream assets in Alabama, Mississippi and south Texas for $220.0 million reduced by purchase price adjustments provided for in the purchase agreement. Sales proceeds, net of transaction costs and other obligations associated with the sale, of $212.0 million were used to repay long-term indebtness. The sale closed on August 6, 2009 and the Partnership recognized a gain of $97.4 million.

On August 31, 2009, the Partnership entered into an agreement to sell its natural gas treating business for $266.0 million, including working capital, and subject to certain closing adjustments.

On October 1, 2009, the sale of the Treating assets was finalized and the Partnership will recognize a gain of approximately $85.0 million. In accordance with FASB ASC 360-10-05-4, the consolidated balance sheet at September 30, 2009 reflects the assets and liabilities as held for sale. The assets and liabilities consisted of the following as of September 30, 2009 (in thousands):

Current assets	$ 9,903
Property and equipment	148,414
Intangible assets	5,538
Goodwill	19,673
Current liabilities	(6,609)
Obligations under capital lease	(2,810)
Total net assets held for sale	$ 174,109

The revenues, operating expenses, general and administrative expenses associated directly with the assets held for sale, depreciation and amortization expense, allocated Texas margin tax and an allocated interest expense related to the operations of the assets held for sale have been segregated from continuing operations and reported as discontinued operations for all periods. In August 2009, the Partnership expensed $2.0 million of unamortized debt issuance costs associated with the bank credit facility and the senior secured notes. This additional write-off of debt issue costs was directly related to the repayments of $143.0 million on the credit facility and $69.0 million on the senior secured notes, from proceeds of the Alabama, Mississippi and south Texas assets disposition. In addition, the Partnership incurred make-whole interest and call premiums of $2.4 million in August 2009 to the holders of the senior secured notes due to the August repayment. These additional interest costs are included in discontinued operations for the three and nine months ended September 30, 2009. No corporate office general and administrative expenses have been allocated to income from discontinued operations. Following are revenues and income from discontinued operations (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Midstream revenues	$ 54,386	$ 455,891	$ 368,111	$ 1,437,562
Treating revenues (1)	$ 13,917	$ 21,678	$ 45,663	$ 56,010
Net income (loss) from discontinued operations, net of tax (1)	$ (3,962)	$ 6,227	$ 4,378	$ 21,792
Gain from sale of discontinued operations, net of tax	$ 97,423	¾	$ 97,423	¾

(1) 2008 values include the Seminole Processing Plant sold in November 2008.

(3) Long-Term Debt

As of September 30, 2009 and December 31, 2008, long-term debt consisted of the following (in thousands):

	September 30, 2009	December 31, 2008
Bank credit facility, interest based on Prime and/or LIBOR plus an applicable margin, interest rates (per the facility) at September 30, 2009 and December 31, 2008 were 6.75% and 3.9%, respectively	$ 676,493	$ 784,000
Senior secured notes (including PIK notes as defined below of $5.5 million), weighted average interest rate at September 30, 2009 and December 31, 2008 were 10.5% and 8.0%, respectively	409,189	479,706
	1,085,682	1,263,706
Less current portion	(21,279)	(9,412)
Debt classified as long-term	$ 1,064,403	$ 1,254,294

CROSSTEX ENERGY, L.P.

Notes To Condensed Consolidated Financial Statements — (Continued)

On October 1, 2009, proceeds from the disposition of the Treating assets as discussed in Note 2 were used to prepay $173.3 million of bank borrowings and $84.8 million of senior secured note borrowings.

Credit Facility. As of September 30, 2009, the Partnership had a bank credit facility with a borrowing capacity of $1.036 billion that matures in June 2011. As of September 30, 2009, $818.9 million was outstanding under the bank credit facility, including $142.4 million of letters of credit, leaving approximately $216.6 million available for future borrowing. The Partnership's borrowing capacity was reduced to $862.2 million on October 1, 2009 due to the $173.3 million prepayment from proceeds of the Treating assets disposition but the amount available for future borrowing of $216.6 million was unchanged.

Obligations under the bank credit facility are secured by first priority liens on all of the Partnership's 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 rank *pari passu* in right of payment with the senior secured notes. The bank credit facility is guaranteed by certain of the Partnership's material subsidiaries. The Partnership may prepay all loans under the credit facility at any time without premium or penalty (other than customary LIBOR breakage costs), subject to certain notice requirements.

On February 27, 2009, the Partnership entered into the Sixth Amendment to the Fourth Amended and Restated Credit Agreement and Consent (the "Sixth Amendment") to its credit facility with the bank lending group. Under the Sixth Amendment, borrowings bear interest at the Partnership's option at the administrative agent's reference rate plus an applicable margin or London Interbank Offering Rate (LIBOR) plus an applicable margin. The applicable margins for the Partnership's interest rate and letter of credit fees vary quarterly based on the Partnership's leverage ratio as defined by the credit facility (the "Leverage Ratio" being generally computed as total funded debt to consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges) and are as follows:

Leverage Ratio	Bank Reference Rate Advances (a)	LIBOR Rate Advances (b)	Letter of Credit Fees (c)	Commitment Fees (d)
Greater than or equal to 5.00 to 1.00	3.00%	4.00%	4.00%	0.50%
Greater than or equal to 4.25 to 1.00 and less than 5.00 to 1.00	2.50%	3.50%	3.50%	0.50%
Greater than or equal to 3.75 to 1.00 and less than 4.25 to 1.00	2.25%	3.25%	3.25%	0.50%
Less than 3.75 to 1.00	1.75%	2.75%	2.75%	0.50%

(a) The applicable margins for the bank reference rate advances ranged from 0% to 0.25% under the bank credit facility prior to the Fifth and Sixth Amendments.

(b) The applicable margins for the LIBOR rate advances ranged from 1.00% to 1.75% under the bank credit facility prior to the Fifth and Sixth Amendments.

(c) The letter of credit fees ranged from 1.00% to 1.75% per annum plus a fronting fee of 0.125% per annum under the bank credit facility prior to the Fifth and Sixth Amendments.

(d) The commitment fees ranged from 0.20% to 0.375% per annum on the unused amount of the credit facility under the bank credit facility prior to the Fifth and Sixth Amendments.

The Sixth Amendment also set a floor for the LIBOR interest rate of 2.75% per annum. The Partnership's applicable margins for its interest rate and letter of credit (LC) fees during the nine months ended September 30, 2009 have been at the high end of these ranges and, based on the Partnership's forecasted leverage ratios for the last quarter of 2009, it expects the applicable margins to be at the high end of these ranges for its interest rate and LC fees.

The Partnership would have been required to pay a leverage fee under the Sixth Amendment if it did not prepay debt and permanently reduce the banks' commitments and senior secured note borrowings by the cumulative amounts of $100.0 million on September 30, 2009, $200.0 million on December 31, 2009 and $300.0 million on March 31, 2010. The disposition of Alabama, Mississippi and south Texas assets that closed on August 6, 2009 satisfied the September 30, 2009 and December 31, 2009 de-leveraging targets and the disposition of Treating assets that closed on October 1, 2009 satisfied the March 31, 2010 de-leveraging target.

Under the Sixth Amendment, the maximum Leverage Ratio (measured quarterly on a rolling four-quarter basis) is as follows:

- 8.25 to 1.00 for the fiscal quarter ending September 30, 2009;
- 8.50 to 1.00 for the fiscal quarter ending December 31, 2009;
- 8.00 to 1.00 for the fiscal quarter ending March 31, 2010;
- 6.65 to 1.00 for the fiscal quarter ending June 30, 2010;
- 5.25 to 1.00 for the fiscal quarter ending September 30, 2010;
- 5.00 to 1.00 for the fiscal quarter ending December 31, 2010;
- 4.50 to 1.00 for any fiscal quarter ending March 31, 2011 through March 31, 2012; and
- 4.25 to 1.00 for any fiscal quarter ending June 30, 2012 and thereafter.

The minimum cash interest coverage ratio (as defined in the agreement, measured quarterly on a rolling four-quarter basis) is as follows under the Sixth Amendment:

- 1.30 to 1.00 for the fiscal quarter ending September 30, 2009;
- 1.15 to 1.00 for the fiscal quarter ending December 31, 2009;
- 1.25 to 1.00 for the fiscal quarter ending March 31, 2010;
- 1.50 to 1.00 for the fiscal quarter ending June 30, 2010;
- 1.75 to 1.00 for any fiscal quarter ending September 30, 2010 and December 31, 2010; and
- 2.50 to 1.00 for any fiscal quarter ending March 31, 2011 and thereafter.

Under the Sixth Amendment, no quarterly distributions may be paid to unitholders unless the PIK notes (as defined below) have been repaid and the Leverage Ratio is less than 4.25 to 1.00. If the Leverage Ratio is between 4.00 to 1.00 and 4.25 to 1.00, the Partnership may make quarterly distributions of up to $0.25 per unit if the PIK notes have been repaid. If the Leverage Ratio is less than 4.00 to 1.00, the Partnership may make quarterly distributions to unitholders from available cash as provided by its partnership agreement if the PIK notes have been repaid. The PIK notes are due six months after the earlier of the refinancing or maturity of its bank credit facility. Based on its forecasted leverage ratios for 2009 and its near term ability to refinance its bank credit facility, the Partnership does not anticipate making quarterly distributions during 2009 other than the distribution paid in February 2009 related to fourth quarter 2008 operating results. The Partnership will not be able to make distributions to its unitholders in future periods if its leverage ratio does not improve.

The Sixth Amendment also limits the Partnership's annual capital expenditures (excluding maintenance capital expenditures) to $120.0 million in 2009 and $75.0 million in 2010 and each year thereafter (with unused amounts in any year being carried forward to the next year).

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Notes To Condensed Consolidated Financial Statements — (Continued)

The Sixth Amendment also revised the terms for mandatory repayment of outstanding indebtedness from asset sales and proceeds from incurrence of unsecured debt and equity issuances. Proceeds from debt issuances and from equity issuances not required to prepay indebtedness are considered to be “Excess Proceeds” under the amended bank credit agreement. The Partnership may retain all Excess Proceeds and the Partnership may only make acquisitions using Excess Proceeds. Net proceeds from asset dispositions are required for prepayment at 100% regardless of the leverage ratio. The following table sets forth the amended prepayment terms:

Leverage Ratio*	% of Net Proceeds from Debt Issuances Required for Prepayment	% of Net Proceeds from Equity Issuance Required for Prepayment
Greater than or equal to 4.50	100%	50%
Greater or equal to 3.50 and less than 4.50	50%	25%
Less than 3.50	0%	0%

* The Leverage Ratio is to be adjusted to give effect to proceeds from debt or equity issuance and the use of such proceeds for each proportional level of Leverage Ratio.

The prepayments are to be applied pro rata based on total debt (including letter of credit obligations) outstanding under the bank credit agreement and the total debt outstanding under the note agreements described below. Any prepayments of advances on the bank credit facility from proceeds from asset sales, debt or equity issuances will permanently reduce the borrowing capacity or commitment under the facility in an amount equal to 100% of the amount of the prepayment. Any such commitment reduction will not reduce the banks’ $300.0 million commitment to issue letters of credit.

In addition, the bank credit facility contains various covenants that, among other restrictions, limit the Partnership’s ability to:

- incur indebtedness;
- grant or assume liens;
- make certain investments;
- sell, transfer, assign or convey assets, or engage in certain mergers or acquisitions;
- change the nature of the Partnership’s business;
- enter into certain commodity contracts;
- make certain amendments to its or the operating partnership’s partnership agreement; and
- engage in transactions with affiliates.

Each of the following will be an event of default under the bank credit facility:

- failure to pay any principal, interest, fees, expenses or other amounts when due;
- failure to observe any agreement, obligation, or covenant in the credit agreement, subject to cure periods for certain failures;
- certain judgments against the Partnership or any of its subsidiaries, in excess of certain allowances;
- certain ERISA events involving the Partnership or its subsidiaries;
- bankruptcy or other insolvency events;
- a change in control (as defined in the credit agreement); and
- the failure of any representation or warranty to be materially true and correct when made.

If an event of default relating to bankruptcy or other insolvency events occurs, all indebtedness under the Partnership's bank credit facility will immediately become due and payable. If any other event of default exists under the bank credit facility, the lenders may accelerate the maturity of the outstanding obligations under the bank credit facility and exercise other rights and remedies.

The Partnership is subject to interest rate risk on its credit facility and has entered into interest rate swaps to reduce this risk. See Note 7 to the financial statements for a discussion of interest rate swaps.

Senior Secured Notes. On February 27, 2009, the Partnership amended its senior note agreement to (i) increase the maximum permitted leverage ratio and to lower the minimum interest coverage ratio it must maintain consistent with the ratios under the Sixth Amendment to the bank credit facility, (ii) revise the mandatory prepayment terms consistent with the terms under the Sixth Amendment to the bank credit facility, (iii) increase the interest rate it pays on the senior secured notes and (iv) provide for the payment of a leverage fee consistent with the terms of the bank credit facility.

Under the amended senior notes agreement, the senior secured notes will accrue additional interest of 1.25% per annum (the "PIK notes") in the form of an increase in the principal amount unless the Partnership's leverage ratio is less than 4.25 to 1.00 as of the end of any fiscal quarter. All PIK notes will be payable six months after the maturity of the bank credit facility, which is currently scheduled to mature in June 2011, or six months after refinancing of such indebtedness if prior to the maturity date.

Per the terms of the amended senior notes agreement the interest rate payable in cash on the Partnership's senior secured notes will increase by 1.25% per annum for any quarter if its leverage ratio as of the most recently ended fiscal quarter was greater than or equal to 4.25 to 1.00. In addition, commencing on June 30, 2012, the interest rate payable in cash on its senior secured notes will increase by 0.50% per annum for any quarter if its leverage as of the most recently ended fiscal quarter was greater than or equal to 4.00 to 1.00, but this incremental interest will not accrue if the Partnership is paying the incremental 1.25% per annum of interest described in the preceding sentence.

The Partnership recognized a $4.7 million loss on extinguishment of debt during the nine months ended September 30, 2009 due to the February 2009 amendment to the senior secured note agreement. The modifications to this agreement pursuant to this amendment were substantive as defined in FASB ASC 470-50, and were accounted for as the extinguishment of the old debt and the creation of new debt. As a result, the unamortized costs associated with the senior secured notes prior to the amendment as well as the fees paid to the senior secured noteholders for the February 2009 amendment were expensed during the nine months ended September 30, 2009.

These notes represent the Partnership's senior secured obligations and rank *pari passu* in right of payment with the bank credit facility. The notes are secured, on an equal and ratable basis with the Partnership's obligations under the credit facility, by first priority liens on all of its material pipeline, gas gathering and processing assets, all material working capital assets and a pledge of all its equity interests in substantially all of its subsidiaries. The senior secured notes are guaranteed by the Partnership's material subsidiaries.

The senior secured notes issued in 2003 are redeemable, at the Partnership's option and subject to certain notice requirements, at a purchase price equal to 100.0% of the principal amount together with accrued interest, plus a make-whole amount determined in accordance with the senior secured note agreement. The senior secured notes issued in 2004, 2005 and 2006 provide for a call premium of 103.5% of par beginning three years after issuance at rates declining from 103.5% to 100.0%. The Partnership incurred make-whole interest and call premiums of $2.4 million in August 2009 as a result of the payment of $69.0 million proceeds from the Alabama, Mississippi and south Texas assets disposition.

If an event of default resulting from bankruptcy or other insolvency events occurs, the senior secured notes will become immediately due and payable. If any other event of default occurs and is continuing, holders of at least 50.1% in principal amount of the outstanding notes may at any time declare all the notes then outstanding to be immediately due and payable. If an event of default relating to the nonpayment of principal, make-whole amounts or interest occurs, any holder of outstanding notes affected by such event of default may declare all the notes held by such holder to be immediately due and payable. The senior secured note agreement relating to the notes contains substantially the same covenants and events of default as the Partnership's bank credit facility.

The Partnership was in compliance with all debt covenants as of September 30, 2009 and expects to be in compliance with debt covenants for the next twelve months.

Intercreditor and Collateral Agency Agreement. In connection with the execution of the bank credit facility and the senior secured note agreement, the lenders under the Partnership's bank credit facility and the purchasers of the senior secured notes have entered into an Intercreditor and Collateral Agency Agreement, which has been acknowledged and agreed to by the Partnership and its subsidiaries. This agreement appointed Bank of America, N.A. to act as collateral agent and authorized Bank of America, N.A. to execute various security documents on behalf of the lenders under the bank credit facility and the purchasers of the senior secured notes. This agreement specifies various rights and obligations of lenders under the Partnership's bank credit facility, holders of the Partnership's senior secured notes and the other parties thereto in respect of the collateral securing the Partnership's obligations under its bank credit facility and the senior secured note agreement. On February 27, 2009, the holders of the Partnership's senior secured notes and a majority of the banks under its bank credit facility entered into an amendment to the Intercreditor and Collateral Agency Agreement, which provides that the PIK notes and certain treasury management obligations will be secured by the collateral for its bank credit facility and the senior secured notes, but only paid with proceeds of collateral after obligations under its bank credit facility and the senior secured notes are paid in full.

(4) Obligations Under Capital Lease

The Partnership entered into various capital leases for certain equipment. Assets under capital leases as of September 30, 2009, excluding assets considered discontinued operations, are summarized as follows (in thousands):

Equipment	$ 27,192
Less: Accumulated amortization	(3,366)
Net assets under capital lease	$ 23,826

The following are the minimum lease payments to be made in the following years indicated for the capital leases in effect as of September 30, 2009 (in thousands):

2009	$ 758
2010	3,062
2011 through 2013 ($3,034 annually)	9,102
Thereafter	15,780
Less: Interest	(4,367)
Net minimum lease payments under capital lease	24,335
Less: Current portion of net minimum lease payments	(3,008)
Long-term portion of net minimum lease payments	$ 21,327

(5) Partners' Capital

(a) *Conversion of Senior Subordinated Series D Units*

On March 23, 2007, the Partnership issued an aggregate of 3,875,340 senior subordinated series D units representing limited partner interests of the Partnership in a private offering. These senior subordinated series D units converted into common units representing limited partner interests of the Partnership on March 23, 2009. Since the Partnership did not make distributions of available cash from operating surplus, as defined in the partnership agreement, of at least $0.62 per unit on each outstanding common unit for the quarter ending December 31, 2008, each senior subordinated series D unit converted into 1.05 common units for a total issuance of 4,069,106 common units.

(b) Cash Distributions

Unless restricted by the terms of its credit facility , the Partnership must make distributions of 100.0% of available cash, as defined in the partnership agreement, within 45 days following the end of each quarter. Distributions will generally be made 98.0% to the common and subordinated 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. Under the quarterly incentive distribution provisions, generally the general partner is entitled to 13.0% of amounts the Partnership distributes in excess of $0.25 per unit, 23.0% of the amounts the Partnership distributes in excess of $0.3125 per unit and 48.0% of amounts the Partnership distributes in excess of $0.375 per unit. No incentive distributions were earned by the general partner for the three and nine months ended September 30, 2009. Incentive distributions totaling $6.7 million and $30.8 million were earned by the general partner for the three and nine months ended September 30, 2008, respectively.

The Partnership's fourth quarter 2008 distribution on its common and subordinated units of $0.25 per unit was paid on February 13, 2009.

See Note 3 for a description of the Partnership's credit facilities which restrict the Partnership's ability to make future distributions.

(c) Earnings per Unit and Dilution Computations

The Partnership's common units and subordinated units participate in earnings and distributions in the same manner for all historical periods and are therefore presented as a single class of common units for earnings per unit computations. The various series of senior subordinated units are also considered common securities, but because they do not participate in cash distributions during the subordination period, they are presented as separate classes of common equity. Each of the series of senior subordinated units was issued at a discount to the market price of the common units they are convertible into at the end of the applicable subordination period. These discounts represent beneficial conversion features (BCFs) under FASB ASC 470-20-25-4. Under FASB ASC 470-20-25-4 and related accounting guidance, a BCF represents a non-cash distribution that is treated in the same way as a cash distribution for earnings per unit computations. Since the conversion of all the series of senior subordinated units into common units are contingent (as described with the terms of such units) until the end of the subordination periods for each series of units, the BCF associated with each series of senior subordinated units is not reflected in earnings per unit until the end of subordination period when the criteria for conversion are met. Following is a summary of the BCFs attributable to the senior subordinated units outstanding during 2008 and 2009 (in thousands):

	BCF	End of Subordination Period
Senior subordinated series C units	$ 121,112	February 2008
Senior subordinated series D units	$ 34,297	March 2009

FASB ASC 260-10-45-61A was issued in May 2008 with an effective date for fiscal years beginning after December 15, 2008 and interim periods within those years. This FASB ASC requires unvested share-based payments that entitle employees to receive non-forfeitable distributions to also be considered participating securities, as defined in FASB ASC 260-10-20. The Partnership was impacted by this FASB ASC and has calculated earnings attributable to unvested restricted units and adjusted earnings per unit calculations for the three and nine months ended September 30, 2009 and the comparative three and nine months ended September 30, 2008 to reflect implementation of the FASB ASC.

The following table reflects the computation of basic earnings per limited partner unit for the periods presented (in thousands except per unit amounts):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Limited partners' interest in net income (loss)	$ 73,508	$ (11,053)	$ 49,743	$ (7,651)
Distributed earnings allocated to:				
Common units(1)	$ ¾	$ 28,266	$ 11,234	$ 73,515
Unvested restricted units	¾	425	134	959
Senior subordinated series C units(2)	¾	¾	¾	121,112
Senior subordinated series D units (3)	¾	¾	34,297	¾
Total distributed earnings	$ ¾	$ 28,691	$ 45,665	$ 195,586
Undistributed income (loss) allocated to:				
Common units(5)	$ 71,431	$ (39,168)	$ 4,026	$ (200,580)
Unvested restricted units (5)	2,077	(576)	52	(2,657)
Senior subordinated series C units	¾	¾	¾	¾

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Notes To Condensed Consolidated Financial Statements — (Continued)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Senior subordinated series D units	¾	¾	¾	¾
Total undistributed earnings (loss)	$ 73,508	$ (39,744)	$ 4,078	$ (203,237)
Net income (loss) allocated to:				
Common units	$ 71,431	$ (10,902)	$ 15,260	$ (127,065)
Unvested restricted units	2,077	(151)	186	(1,698)
Senior subordinated series C units	¾	¾	¾	121,112
Senior subordinated series D units	¾	¾	34,297	¾
Total limited partners' interest in net income (loss)	$ 73,508	$ (11,053)	$ 49,743	$ (7,651)
Limited partners' interest in income from discontinued operations:				
Common units (4)	$ 89,004	$ 6,028	$ 97,717	$ 21,087
Unvested restricted units	2,588	74	2,047	269
Senior subordinated series C and D units	¾	¾	¾	¾
Total income from discontinued operations	$ 91,592	$ 6,102	$ 99,764	$ 21,356
Basic and diluted net income (loss) per unit from continuing operations:				
Basic and diluted common unit	$ (0.36)	$ (0.38)	$ (1.72)	$ (3.57)
Senior subordinated series C unit	$ ¾	$ ¾	$ ¾	$ 9.44
Senior subordinated series D unit	$ ¾	$ ¾	$ 8.85	$ ¾
Basic and diluted net income from discontinued operations:				
Basic common unit	$ 1.81	$ 0.13	$ 2.04	$ 0.51
Diluted common unit	$ 1.79	$ 0.13	$ 1.98	$ 0.51
Senior subordinated series C and D units	$ ¾	$ ¾	$ ¾	$ ¾
Total basic and diluted net income (loss) per unit:				
Basic common unit	$ 1.46	$ (0.24)	$ 0.32	$ (3.06)
Diluted common unit	$ 1.44	$ (0.24)	$ 0.31	$ (3.06)
Senior subordinated series C unit	$ ¾	$ ¾	$ ¾	$ 9.44
Senior subordinated series D unit	$ ¾	$ ¾	$ 8.85	$ ¾

(1) Represents distributions paid to common and subordinated unitholders other than senior subordinated unitholders.

(2) Represents BCF recognized at end of subordination period for senior subordinated series C units.

(3) Represents BCF recognized at end of subordination period for senior subordinated series D units.

(4) Represents 98.0% for the limited partners interest in discontinued operations.

(5) All undistributed earnings and losses are allocated to common units and unvested restricted units during the subordination period.

The following are the unit amounts used to compute the basic and diluted earnings per limited partner unit for the three and nine months ended September 30, 2009 and 2008 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Basic and diluted earnings per unit:				
Weighted average limited partner common units outstanding	49,077	44,869	47,825	41,466
Diluted earnings per unit:				
Weighted average limited partner units outstanding	49,077	44,869	47,825	41,466
Dilutive effect of restricted units issued	671	¾	303	¾
Dilutive effect of senior subordinated units	¾	¾	1,164	¾
Dilutive effect of exercise of options outstanding	4	¾	¾	¾
Dilutive common units	49,752	44,869	49,292	41,466
Weighted average diluted senior subordinated series C units outstanding	¾	¾	¾	12,830
Weighted average diluted senior subordinated series D units outstanding	¾	¾	3,875	¾

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Notes To Condensed Consolidated Financial Statements — (Continued)

All common unit equivalents were anti-dilutive in the three and nine months ended September 30, 2008 because the limited partners were allocated a net loss in these periods.

Net income (loss) for the general partner consists of incentive distributions, 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 adjusted for the CEI stock-based compensation specifically allocated to the general partner. The remaining net income (loss) after these allocations relates to common unitholders. The net income (loss) allocated to the general partner is as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Income allocation for incentive distributions	$ ¾	$ 6,674	$ ¾	$ 30,772
Stock-based compensation attributable to CEI's stock options and restricted shares	(819)	(775)	(2,225)	(3,383)
2% general partner interest in net income (loss)	1,500	(89)	1,015	472
General partner share of net income (loss)	$ 681	$ 5,810	$ (1,210)	$ 27,861

(6) Employee Incentive Plans

(a) Long-Term Incentive Plans

The Partnership accounts for share-based compensation in accordance with the provisions of 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 share-based payment plans for employees, which are described below. Share-based compensation associated with the CEI share-based compensation plans 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 consolidated financial statements with respect to these plans are as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Cost of share-based compensation charged to general and administrative expense	$ 1,883	$ 1,382	$ 5,037	$ 6,867
Cost of share-based compensation charged to operating expense	471	503	1,239	1,383
Total amount charged to income	$ 2,354	$ 1,885	$ 6,276	$ 8,250

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Notes To Condensed Consolidated Financial Statements — (Continued)

(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 nine months ended September 30, 2009 is provided below:

	Nine Months Ended September 30, 2009	
Crosstex Energy, L.P. Restricted Units:	**Number of Units**	**Weighted Average Grant-Date Fair Value**
Non-vested, beginning of period	544,067	$ 31.90
Granted	1,219,725	2.40
Vested*	(184,940)	18.59
Forfeited	(168,712)	9.53
Non-vested, end of period	1,410,140	$ 8.46
Aggregate intrinsic value, end of period (in thousands)	$ 7,431	

* Vested units include 52,604 units withheld for payroll taxes paid on behalf of employees.

The Partnership issued performance-based restricted units in 2007 and 2008 to executive officers. The minimum level of performance-based awards is included in restricted units outstanding and is included in the current share-based compensation cost calculations at September 30, 2009. The achievement of greater than the minimum performance targets in the current business environment is less than probable. All performance-based awards are subject to reevaluation and adjustment until the restricted units vest.

The Partnership awarded 803,632 restricted unit grants during the nine months ended September 30, 2009 to certain of the management team. Half of these units vest one year from the date of grant. The remaining fifty percent of the units are performance-based awards that vest one year from the date of grant if the Partnership achieves certain performance metrics. As of September 30, 2009, the Partnership expects to meet the performance objectives stated in the grant with adjustments deemed necessary due to the disposition of assets in 2009. The performance-based units are shown in the balance of outstanding restricted units and included in the current share-based compensation calculations for the three and nine months ended September 30, 2009.

A summary of the restricted units aggregate intrinsic value (market value at vesting date) and fair value (market value at date of grant) of units vested during the three and nine months ended September 30, 2009 and 2008 are provided below (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
Crosstex Energy, L.P. Restricted Units:	**2009**	**2008**	**2009**	**2008**
Aggregate intrinsic value of units vested	$ 253	$ 303	$ 725	$ 5,515
Fair value of units vested	$ 547	$ 463	$ 3,439	$ 5,898

As of September 30, 2009, there was $4.6 million of unrecognized compensation cost related to non-vested restricted units. That cost is expected to be recognized over a weighted-average period of 1.3 years.

(c) Unit Options

The following weighted average assumptions were used for the Black-Scholes option pricing model for grants during the three and nine months ended September 30, 2009 and 2008:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Crosstex Energy, L.P. Unit Options Granted:	**2009**	**2008**	**2009**	**2008**
Weighted average distribution yield	0%	7.90%	0%	7.15%
Weighted average expected volatility	75.0%	27.0%	75.0%	29.98%
Weighted average risk free interest rate	2.53%	2.99%	2.53%	1.81%
Weighted average expected life	6 years	6 years	6 years	6 years
Weighted average contractual life	10 years	10 years	10 years	10 years
Weighted average fair value of unit options granted	$ 2.08	$ 2.13	$ 2.08	$ 3.48

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Notes To Condensed Consolidated Financial Statements — (Continued)

In May 2009, the Partnership's unitholders approved an amendment to the Partnership's long-term incentive plan to allow an option exchange program. This option exchange program was offered to all eligible employees excluding executive officers and directors because options held by employees were "underwater," meaning the exercise price of the options were higher than the current market price of the common units. The terms of the offer included an exchange ratio of 3 old options for 1 replacement option with an exercise price of $4.80 per common unit (120% of the average closing sales price for five trading days prior to the date of grant) which will vest over 2 years (50% after year 1 and 50% after year 2). In June 2009, a total of 453 employees elected to exchange 1,032,403 old options for 344,319 replacement options pursuant to this option exchange program. There was no incremental compensation cost resulting from the modifications under this option exchange program.

There were no options exercised during the nine months ended September 30, 2009. A summary of the unit option activity for the nine months ended September 30, 2009 is provided below:

Crosstex Energy, L.P. Unit Options:	Nine Months Ended September 30, 2009 Number of Units	Nine Months Ended September 30, 2009 Weighted Average Exercise Price
Outstanding, beginning of period	1,304,194	$ 30.64
Granted	379,756	3.11
Issued in exchange	344,319	4.80
Rendered in exchange	(1,032,403)	31.34
Forfeited	(244,045)	29.05
Expired	(24,116)	28.71
Outstanding, end of period	727,705	$ 6.89
Options exercisable at end of period	124,413	$ 16.42
Weighted average contractual term (years) end of period:		
Options outstanding	8.6	
Options exercisable	3.6	
Aggregate intrinsic value end of period (in thousands):		
Options outstanding	$ 829	
Options exercisable	$ 26	

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 vested (value per Black-Scholes option pricing model at date of grant) during the three and nine months ended September 30, 2009 and 2008 are provided below (in thousands):

Crosstex Energy, L.P., Unit Options:	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Intrinsic value of units options exercised	$ ¾	$ 71	$ ¾	$ 742
Fair value of units vested	$ 91	$ 77	$ 2,621	$ 265

As of September 30, 2009, there was $1.1 million of unrecognized compensation cost related to non-vested unit options. That cost is expected to be recognized over a weighted-average period of 1.3 years.

(d) Crosstex Energy, Inc.'s Stock and Option Plan

CEI's restricted shares are included in stock based compensation at their fair value at the date of grant which is equal to the market value of the common stock on such date. A summary of the restricted share activities for the nine months ended September 30, 2009 is provided below:

Crosstex Energy, Inc. Restricted Shares:	Nine Months Ended September 30, 2009 Number of Shares	Weighted Average Grant-Date Fair Value
Non-vested, beginning of period	604,313	$ 27.62
Granted	406,052	4.13
Vested*	(217,899)	16.70
Forfeited	(92,621)	15.43
Non-vested, end of period	699,845	$ 15.79
Aggregate intrinsic value, end of period (in thousands)	$ 3,695	

* Vested shares include 67,733 shares withheld for payroll taxes paid on behalf of employees.

The Company issued performance-based restricted shares in 2007 and 2008 to executive officers. The minimum level of performance-based awards is included in restricted shares outstanding and is included in the current share-based compensation cost calculations at September 30, 2009. The achievement of greater than the minimum performance targets in the current business environment is less than probable. All performance-based awards are subject to reevaluation and adjustment until the restricted shares vest.

A summary of the restricted shares' aggregate intrinsic value (market value at vesting date) and fair value (market value at date of grant) of shares vested during the three and nine months ended September 30, 2009 and 2008 are provided below (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
Crosstex Energy, Inc. Restricted Shares:	2009	2008	2009	2008
Aggregate intrinsic value of shares vested	$ 107	$ 606	$ 831	$ 12,979
Fair value of shares vested	$ 371	$ 517	$ 3,640	$ 6,390

As of September 30, 2009 there was $4.4 million of unrecognized compensation costs related to non-vested CEI restricted shares for officers and employees. The cost is expected to be recognized over a weighted average period of 1.4 years.

CEI Stock Options

No CEI stock options were granted to, or exercised or forfeited attributable to officers or employees of the Partnership during the three and nine months ended September 30, 2009 and 2008. The following is a summary of the CEI stock options outstanding attributable to officers and employees of the Partnership as of September 30, 2009:

Outstanding stock options (15,000 exercisable)	30,000
Weighted average exercise price	$ 13.33
Aggregate intrinsic value outstanding	$ ¾
Weighted average remaining contractual term	5.2 years

As of September 30, 2009, there was less than $0.1 million of unrecognized compensation costs related to non-vested CEI stock options. The cost is expected to be recognized over a weighted average period of 0.1 years.

(7) Derivatives

The Partnership manages exposure to interest rate risk and commodity price risk through the use of derivative instruments and hedging activities. FASB ASC 815-10-65-1 was issued in March 2008 requiring additional disclosures on derivative instruments that would provide insight into the reason for the use of derivative instruments, give transparency to the location of derivatives within the financial statements and the financial impact of the derivative activity and provide disclosure about credit risk to provide additional information about liquidity. These disclosure requirements are in addition to those already required under FASB ASC 815. The Partnership has historically presented detailed information about derivative activities, but has updated the current disclosure to provide the requirements of FASB ASC 815-10-65-1.

Interest Rate Swaps

The Partnership is subject to interest rate risk on its credit facility and has entered into interest rate swaps to reduce this risk.

The Partnership entered into eight interest rate swaps prior to 2008. Each swap fixed the three month LIBOR rate, prior to credit margin, at the indicated rates for the specified amounts of related debt outstanding over the term of each swap agreement. In January 2008, the Partnership amended existing swaps with the counterparties in order to reduce the fixed rates and extend the terms of the existing swaps by one year and entered into one new swap. The table below reflects the swaps as amended:

Trade Date	Term	From	To	Rate	Notional Amounts (in thousands)
November 14, 2006	4 years	November 28, 2006	November 30, 2010	4.3800%	$ 50,000
March 13, 2007	4 years	March 30, 2007	March 31, 2011	4.3950%	50,000
July 30, 2007	4 years	August 30, 2007	August 30, 2011	4.6850%	100,000
August 6, 2007	4 years	August 30, 2007	August 31, 2011	4.6150%	50,000
August 9, 2007	3 years	November 30, 2007	November 30, 2010	4.4350%	50,000
August 16, 2007*	4 years	October 31, 2007	October 31, 2011	4.4875%	100,000
September 5, 2007	4 years	September 28, 2007	September 28, 2011	4.4900%	50,000
					$ 450,000

* Amended swap is a combination of two swaps that each had a notional amount of $50.0 million with the same original term.

The Partnership had previously elected to designate all interest rate swaps (except the November 2006 swap) as cash flow hedges for FASB ASC 815 accounting treatment. Accordingly, unrealized gains and losses relating to the designated interest rate swaps were recorded in accumulated other comprehensive income. Immediately prior to the January 2008 amendments, these swaps were de-designated as cash flow hedges. The unrealized loss in accumulated other comprehensive income of $17.0 million at the de-designation date is being reclassified to earnings over the remaining original terms of the swaps using the effective loss of interest method. The related loss reclassified to earnings and included in other income (expense) in the consolidated statements of operations as part of interest expense is $1.7 million for both the three month periods ended September 30, 2009 and 2008, and $5.1 million and $4.7 million during the nine months ended September 30, 2009 and 2008, respectively.

The Partnership has elected not to designate any of the amended swaps as cash flow hedges for FASB ASC 815 treatment. Accordingly, unrealized gains and losses are recorded through the consolidated statement of operations in other income (expense) as part of interest expense, net, over the period hedged.

In September 2008, the Partnership entered into four additional interest rate swaps. The effect of the new interest rate swaps was to convert the floating rate portion of the original swaps on $450.0 million from three month LIBOR to one month LIBOR. The Partnership received a cash settlement in September 2008 of $1.4 million which represented the present value of the basis point differential between one month LIBOR and three month LIBOR.

The table below aligns the new swap, which receives one month LIBOR and pays three month LIBOR, with the original interest rate swaps.

Original Swap Trade Date	New Trade Date	From	To	Notional Amounts (in thousands)
March 13, 2007	September 12, 2008	September 30, 2008	March 31, 2011	$ 50,000
September 5, 2007	September 12, 2008	September 30, 2008	September 28, 2011	50,000
August 16, 2007	September 12, 2008	October 30, 2008	October 31, 2011	100,000
November 14, 2006	September 12, 2008	November 28, 2008	November 30, 2010	50,000
August 9, 2007	September 12, 2008	November 28, 2008	November 30, 2010	50,000
July 30, 2007	September 12, 2008	November 28, 2008	August 30, 2011	100,000
August 6, 2007	September 23, 2008	November 28, 2008	August 30, 2011	50,000
				$ 450,000

CROSSTEX ENERGY, L.P.

Notes To Condensed Consolidated Financial Statements — (Continued)

The impact of the interest rate swaps on net income (loss) is included in other income (expense) in the consolidated statements of operations as part of interest expense, net, as follows (in thousands):

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Change in fair value of derivatives that do not qualify for hedge accounting	$ (948)	$ (3,853)	$ 2,470	$ 2,210
Realized losses on derivatives	(4,914)	(583)	(14,130)	(2,547)
	$ (5,862)	$ (4,436)	$ (11,660)	$ (337)

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

	September 30, 2009	December 31, 2008
Fair value of derivative assets — current	$ ¾	$ 149
Fair value of derivative liabilities — current	(18,234)	(17,217)
Fair value of derivative liabilities — long-term	(9,786)	(18,391)
Net fair value of derivatives	$ (28,020)	$ (35,459)

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 prices and location risk 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 hedges. These transactions include swing swaps, third party on-system financial swaps, marketing financial swaps, storage swaps, basis swaps, processing margin swaps, and liquid swaps. 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. Marketing financial swaps are similar to on-system financial swaps, but are entered into for customers not connected to the Partnership’s systems. Storage swaps transactions protect against changes in the value of gas that the Partnership has stored to serve various operational requirements. 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 or to bypass equity gas. Liquids financial swaps are used to hedge price risk on percent of liquids (POL) contracts.

CROSSTEX ENERGY, L.P.

Notes To Condensed Consolidated Financial Statements — (Continued)

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

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Change in fair value of derivatives that do not qualify for hedge accounting	$ (1,126)	$ 99	$ (662)	$ (713)
Realized (gain) loss on derivatives	29	(3,087)	(6,311)	(6,800)
Ineffective portion of derivatives qualifying for hedge accounting	(11)	(152)	(14)	(17)
Net gains related to commodity swaps	(1,108)	(3,140)	(6,987)	(7,530)
Adjusted for net gains (losses) included in income from discontinued operations	(564)	684	264	3,244
Gain on derivatives included in continuing operations	$ (1,672)	$ (2,456)	$ (6,723)	$ (4,286)

The fair value of derivative assets and liabilities relating to commodity swaps excluding net fair value of derivatives liability included in assets held for sale of $1.0 million are as follows (in thousands):

	September 30, 2009	December 31, 2008
Fair value of derivative assets — current, designated	$ 2,094	$ 13,714
Fair value of derivative assets — current, non-designated	8,328	13,303
Fair value of derivative assets — long term, designated	29	¾
Fair value of derivative assets — long term, non-designated	8,672	4,628
Fair value of derivative liabilities — current, designated	(314)	¾
Fair value of derivative liabilities — current, non-designated	(6,013)	(11,289)
Fair value of derivative liabilities — long term, designated	(29)	¾
Fair value of derivative liabilities — long-term, non-designated	(8,064)	(4,384)
Net fair value of derivatives	$ 4,703	$ 15,972

Set forth below is the summarized notional volume and fair value of all instruments held for price risk management purposes and related physical offsets at September 30, 2009 (all gas volumes are expressed in MMBtu's and all liquids volumes are expressed in gallons). The remaining term of the contracts extend no later than December 2010 for derivatives, except for certain basis swaps that extend to March 2012. 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.

September 30, 2009		
Transaction Type	**Volume** (In thousands)	**Fair Value** (In thousands)
*Cash Flow Hedges:**		
Natural gas swaps (short contracts)	(102)	$ 335
Liquids swaps (short contracts)	(11,212)	1,442
Liquids swaps (long contracts)	1,247	3
Total swaps designated as cash flow hedges		$ 1,780
*Mark to Market Derivatives:**		
Swing swaps (long contracts)	406	$ (1)
Physical offsets to swing swap transactions (short contracts)	(406)	¾
Swing swaps (short contracts)	(3,884)	(37)
Physical offsets to swing swap transactions (long contracts)	3,884	¾
Basis swaps (long contracts)	78,596	11,796
Physical offsets to basis swap transactions (short contracts)	(450)	1,653
Basis swaps (short contracts)	(56,730)	(8,607)
Physical offsets to basis swap transactions (long contracts)	761	(1,661)
Third-party on-system financial swaps (long contracts)	339	(992)
Third-party on-system financial swaps (short contracts)	(122)	(43)
Processing margin hedges — liquids (short contracts)	(17,639)	(679)

September 30, 2009		
Transaction Type	**Volume**	**Fair Value**
	(In thousands)	
Processing margin hedges — gas (long contracts)	2,002	649
Liquids swaps — non-designated (short contracts)	(1,233)	(15)
Storage swap transactions (short contracts)	(360)	(175)
Less: Mark to market derivatives included in assets held for sale		1,035
Total Mark to market derivatives		$ 2,923

* All are gas contracts, volume in MMBtu's, except for processing margin hedges — liquids and all liquids swaps (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 that allow for netting of swap contract receivables and payables in the event of default by either party. If the Partnership's counterparties failed to perform under existing swap contracts, the Partnership's maximum loss of $22.1 million would be reduced to $11.1 million due to the netting feature. If the counterparties failed to completely perform according to the terms of the contracts the maximum loss the Partnership would sustain is $1.6 million with financial institutions and $9.5 million with other energy companies.

Impact of Cash Flow Hedges

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
Increase (Decrease) in Revenue	**2009**	**2008**	**2009**	**2008**
Natural gas	$ 605	$ (811)	$ 1,762	$ (691)
Liquids	1,155	(3,370)	8,921	(14,305)
Adjusted for realized (gain) loss included in income from discontinued operations	(187)	1,427	(852)	3,560
	$ 1,573	$ (2,754)	$ 9,831	$ (11,436)

Natural Gas

As of September 30, 2009, an unrealized derivative fair value gain of $0.3 million related to cash flow hedges of gas price risk was recorded in accumulated other comprehensive income (loss) and is expected to be reclassified into earnings through December 2009. 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 amount is not reflected above.

The settlement of cash flow hedge contracts related to October 2009 gas production increased gas revenue by approximately $0.1 million.

Liquids

As of September 30, 2009, an unrealized derivative fair value gain of $1.4 million related to cash flow hedges of liquids price risk was recorded in accumulated other comprehensive income (loss). Of this net amount, a $1.4 million gain is expected to be reclassified into earnings through September 2010. 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 amount is not reflected above.

CROSSTEX ENERGY, L.P.

Notes To Condensed Consolidated Financial Statements — (Continued)

Derivatives Other Than Cash Flow Hedges

Assets and liabilities related to third party derivative contracts, swing swaps, basis swaps, storage swaps and processing margin 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 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
September 30, 2009	$ 2,315	$ 561	$ 47	$ 2,923

(8) Fair Value Measurements

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

FASB ASC 820 establishes 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 swaps and interest rate swap contracts which are not traded on a public exchange. The fair values of commodity swap contracts are determined based on inputs that are readily available in public markets or can be derived from information available in publicly quoted markets. The Partnership determines the value of interest rate swap contracts by utilizing inputs and quotes from the counterparties to these contracts. The reasonableness of these inputs and quotes is verified by comparing similar inputs and quotes from other counterparties as of each date for which financial statements are prepared. The Partnership's contracts are all level two contracts under FASB ASC 820.

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

	Level 2
Interest Rate Swaps*	$ (28,020)
Commodity Swaps*	3,668
Adjusted for net liability value of commodity swaps included in assets held for sale	1,035
Total	$ (23,317)

* Unrealized gains or losses on commodity derivatives qualifying for hedge accounting are recorded in accumulated other comprehensive income (loss) at each measurement date. Accumulated other comprehensive income (loss) also includes the unrealized losses on interest rate swaps of $17.0 million recorded prior to de-designation in January 2008, of which $11.5 million has been amortized to earnings through September 2009.

(9) Fair Value of Financial Instruments

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

	September 30, 2009		December 31, 2008	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Cash and cash equivalents	$ 905	$ 905	$ 1,636	$ 1,636
Trade accounts receivable and accrued revenues	165,866	165,866	341,853	341,853
Fair value of derivative assets	19,123	19,123	31,794	31,794
Note receivable	67	67	375	375
Accounts payable, drafts payable and accrued gas purchases	121,465	121,465	315,622	315,622
Long-term debt	1,085,682	1,068,590	1,263,706	1,158,351
Obligations under capital lease	24,335	23,128	27,896	27,269
Fair value of derivative liabilities	42,440	42,440	51,281	51,281

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 carrying value for the note receivable approximates the fair value because this note earns interest based on the current prime rate.

The Partnership's long-term debt was comprised of borrowings under a revolving credit facility totaling $676.5 million and $784.0 million as of September 30, 2009 and December 31, 2008, respectively, which accrues interest under a floating interest rate structure. Accordingly, the carrying value of such indebtedness approximates fair value for the amounts outstanding under the credit facility. As of September 30, 2009 and December 31, 2008, the Partnership also had borrowings totaling $409.2 million and $479.7 million, respectively, under senior secured notes with a weighted average interest rate of 10.5% and 8.0%, respectively. The fair value of these borrowings as of September 30, 2009 and December 31, 2008 were adjusted to reflect current market interest rate for such borrowings as of September 30, 2009 and December 31, 2008, respectively. 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.

(10) Other Income

The Partnership recorded $7.7 million in other income during the nine months ended September 30, 2008, primarily from the settlement of disputed liabilities that were assumed with an acquisition.

(11) Commitments and Contingencies

(a) Employment Agreements

Certain members of management of the Partnership are parties to employment contracts with the general partner. The employment agreements provide those senior managers with severance payments in certain circumstances and 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) 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.

In December 2008, Denbury Onshore, LLC ("Denbury") initiated formal arbitration proceedings against Crosstex CCNG Processing Ltd. ("Crosstex Processing"), Crosstex Energy Services, L.P. ("Crosstex Energy"), Crosstex North Texas Gathering, L.P. ("Crosstex Gathering") and Crosstex Gulf Coast Marketing, Ltd. ("Crosstex Marketing"), all wholly-owned subsidiaries of the Partnership, asserting a claim for breach of contract under a gas processing agreement. The Crosstex parties filed answers denying Denbury's allegations and asserting certain counterclaims. Crosstex Energy, Crosstex Marketing, and Crosstex Gathering also asserted that they are improper parties to the arbitration because they are not parties to the gas processing agreement. Denbury amended its pleadings to include a fraudulent inducement claim and seek punitive damages against the Crosstex entities, but has since dropped those claims. The Crosstex entities have withdrawn their counterclaims pursuant to a stipulation among the parties. Denbury's current claim is for breach of contract damages in the amount of $16.2 million, plus interest and attorney's fees. A three-person arbitration panel is scheduled to conduct a hearing on the merits commencing December 7, 2009. Although it is not possible to predict with certainty the ultimate outcome of this matter, the Partnership does not believe this will have a material adverse impact on its consolidated results of operations or financial position.

The Partnership (or its subsidiaries) is defending several 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. Although it is not possible to predict the ultimate outcomes of these matters, the Partnership does not believe that these claims will have a material adverse impact on its consolidated results of operations or financial condition.

On July 22, 2008, SemStream, L.P. and certain of its subsidiaries filed voluntary petitions for reorganization under Chapter 11 of the U.S. Bankruptcy Code. As of July 22, 2008, SemStream, L.P. owed the Partnership approximately $6.2 million, including approximately $3.9 million for June 2008 sales and approximately $2.3 million for July 2008 sales. The Partnership believes the July sales of $2.3 million will receive "administrative claim" status in the bankruptcy proceeding. The debtor's schedules acknowledge its obligation to Crosstex for an administrative claim in the amount of $2.3 million, but it remains subject to an objection by the lenders' agent. The Partnership evaluated these receivables for collectibility and provided a valuation allowance of $3.1 million during the year ended December 31, 2008 and $0.8 million during the nine months ended September 30, 2009.

(12) Subsequent Events

The Partnership evaluated events subsequent to the quarter ending September 30, 2009 through the date of the issuance of the financial statements on November 6, 2009. Events occurring subsequent to September 30, 2009 include the closing of the sale of Treating assets disclosed in Note 2 to the financial statements on October 1, 2009.

Additionally, on October 15, 2009, the Partnership acquired the Eunice NGL processing plant and fractionation facility for $23.5 million in cash and the assumption of $18.1 million in debt. In November 2005, the Partnership acquired the contract rights associated with the Eunice plant as part of the south Louisiana acquisition and has operated and managed the plant under an operating lease with an unaffiliated third party for the past four years. In October 2009, the Partnership acquired the physical plant from the third party lessor under this operating lease.

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

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

Overview

We are a Delaware limited partnership formed on July 12, 2002 to indirectly acquire substantially all of the assets, liabilities and operations of our predecessor, Crosstex Energy Services, Ltd. Historically we have operated with two industry segments, Midstream and Treating, with a geographic focus along the Texas Gulf Coast, in the north Texas Barnett Shale area, and in Louisiana and Mississippi. In August 2009 we sold our Alabama, Mississippi and south Texas properties and in October 2009 we sold our Treating assets as discussed more fully under "Recent Developments." Our primary focus for our continuing operations is on the gathering, processing, transmission and marketing of natural gas and natural gas liquids (NGLs), and providing certain producer services. Our geographic focus is in the north Texas Barnett Shale area and in Louisiana. We manage our operations by focusing on gross margin because our business is generally to purchase and resell natural gas for a margin, or to gather, process, transport, and market natural gas and NGLs for a fee. We buy and sell most of our natural gas at a fixed relationship to the relevant index price so our margins for gathering and transmission are not significantly affected by changes in natural gas prices. In addition, we receive certain fees for processing based on a percentage of the liquids produced and enter into hedge contracts for our expected share of the liquids produced to protect our margins from changes in liquids prices.

Our margins are determined primarily by the volumes of natural gas gathered, transported, purchased and sold through our pipeline systems and processed at our processing facilities and the volumes of NGLs handled at our fractionation facilities. We generate revenues from four primary sources:

- purchasing and reselling or transporting natural gas on the pipeline systems we own;
- processing natural gas at our processing plants and fractionating and marketing the recovered NGLs;
- providing compression services; and
- providing off-system marketing services for producers.

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. In our purchase/sale transactions, the resale price is generally based on the same index at which the gas was purchased. 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 also realize gross margins from processing services through three different contract arrangements: processing margins (margin), percentage of liquids (POL) or fee based. Under a margin contract arrangement, our gross margins are higher during periods of high liquid prices relative to natural gas prices. Gross margin results under a POL contract are impacted only by the value of the liquids produced. Under fee based contracts our margins are driven by throughput volume.

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 and associated transportation and communication costs, property insurance, ad valorem taxes, repair and maintenance expenses, measurement 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 volumes moved through the asset.

Recent Developments

During the last half of 2008 global financial markets and economic conditions were disrupted by numerous events that severely constrained liquidity in the capital markets throughout the United States and around the world. Although financial markets and economic conditions have continued to be difficult during 2009, financial markets and economic conditions have been more stable and somewhat improved during the third quarter of 2009.

Conditions in our industry have continued to be challenging in 2009. For example:

- Prices of oil, natural gas and NGLs in 2009 remain below the market price realized throughout most of 2008. Crude oil prices (based on NYMEX futures daily close prices for the prompt month) have improved during 2009 with prices ranging from a low of $33.98 per Bbl on February 12, 2009 to a high of $74.37 per Bbl on August 24, 2009. Weighted average NGL prices (based on the OPIS Mt. Belvieu daily average spot liquids prices) have also improved with prices ranging from a low of $0.58 per gallon on March 16, 2009 to a high of $0.92 per gallon on September 18, 2009. Natural gas prices have declined during 2009 with prices ranging from a high of $6.10 per MMBtu on January 7, 2009 to a low of $1.85 per MMBtu on September 8, 2009. (These prices do not address increases or decreases that may have occurred subsequent to September 30, 2009.)

- Although NGL prices have improved during 2009 together with the related fractionation spreads and POL margin, our processing margins in 2009 have been lower than the processing margins realized in 2008. For the nine months ended September 30, 2009, approximately 32.9% of our gross margin was attributable to gas processing as compared to 48.5% of our gross margin for the nine months ended September 30, 2008.

- The decline in drilling activity by gas producers in our areas of operations that began during the fourth quarter of 2008 as a result of the global economic crisis has continued. Several of our customers, including one of our largest customers in the Barnett Shale, substantially reduced drilling activity during 2009 as compared to their drilling levels during 2008.

- Several offshore production platforms and pipelines that transport gas production to our Pelican, Eunice and Sabine Pass processing plants in south Louisiana were damaged by hurricanes Gustav and Ike, which came ashore in the Gulf Coast in September 2008. Substantially all of the production from the pipeline systems supplying the Pelican, Eunice and Sabine plants has been restored to pre-hurricane levels as of September 30, 2009 but our processing volumes at the plants during the nine months ended September 30, 2009 were negatively impacted by lower pipeline system supplies while these pipeline systems were being repaired.

Despite the weaker commodity environment and reduced drilling activity, we are positioning ourselves to benefit from a recovering economy. In particular:

- We adjusted our business strategy for 2009 to focus on maximizing our liquidity, maintaining a stable asset base, and improving the profitability of our assets by increasing their utilization while controlling costs. We have also reduced our capital expenditures.

- We completed the disposition of certain non-strategic assets including the February 2009 sale of the Arkoma system for approximately $10.7 million, the August 2009 sale of our Alabama, Mississippi and south Texas properties for approximately $220.0 million, and the October 2009 sale of our Treating assets for $266.0 million. Substantially all of the proceeds from the August and October 2009 asset sales were used to repay long-term debt.

- We amended our bank credit facility and our senior secured note agreements in February 2009 to negotiate terms that facilitate our compliance with debt covenants while we operate our assets during the current difficult economic conditions. The terms of the amended agreements allow us to maintain a higher level of leverage and to maintain a lower interest coverage ratio; however, our interest costs have increased and our ability to pay distributions and incur additional indebtedness has been restricted because we are operating at higher leverage ratios.

Results of Operations

Set forth in the table below is certain financial and operating data for the periods indicated and excludes financial and operating data considered discontinued operations.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(Dollars in millions)			
Midstream revenues	$ 349.2	$ 854.3	$ 1,049.5	$ 2,650.1
Purchased gas	(269.5)	(775.8)	(824.8)	(2,411.0)
Profit on energy trading activities	1.5	0.7	3.6	2.3
Total gross margin	$ 81.2	$ 79.2	$ 228.3	$ 241.4
Volumes (MMBtu/d):				
Gathering and transportation	2,038,000	2,073,000	2,069,000	2,030,000
Processing	1,257,000	1,499,000	1,183,000	1,805,000
Producer services	95,000	80,000	87,000	81,000

Three Months Ended September 30, 2009 Compared to Three Months Ended September 30, 2008

Gross Margin and Profit on Energy Trading Activities. Gross margin was $81.2 million for the three months ended September 30, 2009 compared to $79.2 million for the three months ended September 30, 2008, an increase of $2.0 million, or 2.6%. The increase was primarily due to higher margins on our gathering and transmission throughput volume. These increases were partially offset by gross margin declines in the processing business due to a less favorable NGL market. Profit on energy trading activities increased for the comparative periods by approximately $0.8 million.

The LIG gathering and transmission system contributed gross margin growth of $4.2 million for the comparative periods primarily due to improved pricing and higher volumes on the northern part of the system offsetting a decrease in sales volume at southern delivery points. Throughput and plant inlet volumes in the north Texas region were relatively unchanged for the three months ended September 30, 2009 over the same period in 2008. However there were moderate gross margin gains in the north Texas region for gathering and transmission systems and processing plants of $1.7 million and $0.5 million, respectively. The weaker processing environment contributed to a significant decline in the gross margins for processing plants in Louisiana for the quarter ended September 30, 2009. Overall the plants in the region reported a margin decrease of approximately $4.8 million. The primary contributors to this decrease were the Eunice, Gibson and Pelican plants which had gross margin declines of $3.5 million, $3.2 million and $1.7 million, respectively. These were offset by a gross margin increase at the Riverside facility of $4.2 million primarily due to a mark to market loss on inventory recorded in the third quarter of 2008. The Arkoma system, which was sold in April 2009, created a negative gross margin variance of $0.7 million when compared to the same period in 2008.

Operating Expenses. Operating expenses were $29.0 million for the three months ended September 30, 2009 compared to $34.4 million for the three months ended September 30, 2008, a decrease of $5.4 million, or 15.6%. The decrease is primarily attributable to initiatives undertaken in late 2008 and early 2009 to reduce expenses.

General and Administrative Expenses. General and administrative expenses of $16.1 million for the three months ended September 30, 2009 is relatively flat versus the same period in 2008 even though 2009 expense includes a one time charge of $0.9 million for severance costs related to asset sales.

Gain/Loss on Derivatives. We had a gain on commodity derivatives of $1.7 million for the three months ended September 30, 2009 compared to a gain of $2.5 million for the three months ended September 30, 2008. The derivative transaction types contributing to the net gain are as follows (in millions):

	Three Months Ended September 30,			
	2009		2008	
(Gain)/Loss on Derivatives:	**Total**	**Realized**	**Total**	**Realized**
Basis swaps	$ (1.8)	$ (0.7)	$ (1.4)	$ (2.7)
Processing margin hedges	0.5	0.8	(1.0)	—
Other	0.2	(0.1)	(0.7)	(0.5)
	(1.1)	—	(3.1)	(3.2)
Adjusted for derivative gains (losses) related to assets held for sale and included in income from discontinued operations	(0.5)	—	0.6	1.8
Gain on Derivatives	$ (1.6)	$ —	$ (2.5)	$ (1.4)

Depreciation and Amortization. Depreciation and amortization expenses were $31.2 million for the three months ended September 30, 2009 compared to $26.9 million for the three months ended September 30, 2008, an increase of $4.3 million, or 15.8%. The increase is primarily attributable to the north Texas expansion and north LIG expansion.

Interest Expense. Interest expense was $26.6 million for the three months ended September 30, 2009 compared to $14.2 million for the three months ended September 30, 2008, an increase of $12.3 million. Interest expense increased by $9.2 million on the senior notes (including PIK interest) and the credit facility due to an increase in interest rates from the February 2009 amendments to the debt agreements. Additionally the interest rate derivatives activity yielded an increase of $1.5 million in expense due to the decrease in LIBOR rates. Net interest expense consists of the following (in millions):

	Three Months Ended September 30,	
	2009	2008
Senior notes	$ 7.7	$ 5.5
Credit facility	9.2	3.8
PIK Notes	1.6	—
Mark to market interest rate swaps	1.0	3.8
Realized interest rate swap losses	4.9	0.6
Capitalized interest	(0.1)	(0.5)
Interest income	(0.1)	(0.1)
Amortization of debt issue cost	2.0	0.7
Other	0.4	0.4
Total	$ 26.6	$ 14.2

Income Taxes. Income tax expense was $0.4 million for the three months ended September 30, 2009 compared to $1.6 million for the three months ended September 30, 2008, a decrease of $1.2 million. The decrease in expense between periods was because the income tax expense for the three months ended September 30, 2008 included an adjustment of $0.8 million for an unrecognized tax benefit to the Texas margin tax.

Discontinued Operations. We sold the following non-strategic assets over the past year and used the proceeds from such sales to repay long-term indebtness:

Assets	Date of Sale
12.4% interest in the Seminole Gas Processing Plant	November 2008
Arkoma assets	January 2009
Alabama, Mississippi and south Texas assets	August 2009
Treating assets	October 2009

In accordance with FASB ASC 360-10-05-4, the assets and liabilities and the results of operations related to each of the assets listed above (except the Arkoma assets which were immaterial to the financial statement presentations) were segregated to assets and liabilities held for sale and are presented in income from discontinued operations for the comparative periods in the statements of operations. Revenues, operating expenses, general and administrative expenses associated directly to the assets held for sale, depreciation and amortization, allocated Texas margin tax and allocated interest are reflected in the income from discontinued operations. In August 2009, we expensed $2.0 million of unamortized debt issuance costs associated with the bank credit facility and the senior secured notes due to the repayments of $143.0 million and $69.0 million, respectively, in borrowings from proceeds of the Alabama, Mississippi and south Texas assets disposition. In addition, we incurred make-whole interest and call premiums of $2.4 million in August 2009 to the holders of the senior secured notes due to the call premium on the August repayment. These additional interest costs are included in discontinued operations for the three months ended September 30, 2009. No corporate office general and administrative expenses have been allocated to income from discontinued operations. Following are the components of revenues and earnings from discontinued operations and operating data (dollars in millions):

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008
Midstream revenues	$ 54.4	$ 455.9
Treating revenues	$ 13.9	$ 21.7
Net income (loss) from discontinued operations	$ (4.0)	$ 6.2
Gain from sale of discontinued operations (1)	$ 97.4	—
Gathering and Transmission Volumes (MMBtu/d)	563,000	584,000
Processing Volumes (MMBtu/d)	178,000	184,000

(1) Gain on sale of discontinued operations relate to disposition of Alabama, Mississippi and south Texas.

Nine Months Ended September 30, 2009 Compared to Nine Months Ended September 30, 2008

Gross Margin and Profit on Energy Trading Activities. Gross margin was $228.3 million for the nine months ended September 30, 2009 compared to $241.4 million for the nine months ended September 30, 2008, a decrease of $13.1 million, or 5.4%. The decrease was primarily due to weakness in the natural gas processing business driven by less favorable NGL markets. These decreases were partially offset by margin improvement on the gathering and transmission assets. Profit on energy trading activities increased for the comparative periods by approximately $1.3 million.

The weaker processing environment contributed to a significant decline in the gross margins for processing plants in Louisiana for the nine months ended September 30, 2009. Overall the plants in the region reported a margin decrease of approximately $29.2 million. The primary contributors to this decrease were the Gibson, Plaquemine and Eunice plants which had gross margin declines of $9.2 million, $8.5 million and $3.6 million, respectively. The Crosstex Pipeline system in east Texas had a gross margin decline of $2.2 million primarily due to a decline in throughput volumes. The Arkoma system, which was sold in February 2009, created a negative gross margin variance of $2.0 million when compared to the same period in 2008. System expansion in the north Texas region contributed $14.9 million of gross margin growth for the nine months ended September 30, 2009 over the same period in 2008. The gathering systems in the region and North Texas Pipeline (NTP) accounted for approximately $16.4 million of gross margin increases. This increase was partially offset by a gross margin decline of $1.5 million on the processing facilities in north Texas. The LIG gathering and transmission system contributed gross margin growth of $3.6 million for the comparative periods primarily due to improved pricing and higher volumes on the northern part of the system offsetting a decrease in sales volume at southern delivery points.

Operating Expenses. Operating expenses were $84.7 million for the nine months ended September 30, 2009 compared to $93.7 million for the nine months ended September 30, 2008, a decrease of $9.0 million, or 9.6%. The decrease is primarily attributable to initiatives undertaken in late 2008 and early 2009 to reduce expenses.

General and Administrative Expenses. General and administrative expenses were $43.6 million for the nine months ended September 30, 2009 compared to $48.0 million for the nine months ended September 30, 2008, a decrease of $4.4 million, or 9.1%. The decrease is a result of strategic initiatives undertaken to reduce expenses and primarily relate to workforce reductions. Severance costs of $0.9 million related to asset sales are included in the 2009 general and administrative expenses.

Gain/Loss on Derivatives. We had a gain on commodity derivatives of $6.7 million for the nine months ended September 30, 2009 compared to a gain of $4.3 million for the nine months ended September 30, 2008. The derivative transaction types contributing to the net gain are as follows (in millions):

	Nine Months Ended September 30,			
	2009		2008	
(Gain)/Loss on Derivatives:	**Total**	**Realized**	**Total**	**Realized**
Basis swaps	$ (3.6)	$ (1.7)	$ (6.1)	$ (6.3)
Processing margin hedges	(3.2)	(3.2)	(0.8)	0.2
Other	(0.2)	(1.4)	(0.6)	(0.6)
	(7.0)	(6.3)	(7.5)	(6.7)
Adjusted for derivative gains related to assets held for sale and included in income from discontinued operations	0.3	0.5	3.2	3.0
Gain on Derivatives	$ (6.7)	$ (5.8)	$ (4.3)	$ (3.7)

Depreciation and Amortization. Depreciation and amortization expenses were $90.8 million for the nine months ended September 30, 2009 compared to $79.2 million for the nine months ended September 30, 2008, an increase of $11.6 million, or 14.7%. The increase is primarily attributable to the north Texas expansion and north LIG expansion.

Interest Expense. Interest expense was $64.8 million for the nine months ended September 30, 2009 compared to $32.8 million for the nine months ended September 30, 2008, an increase of $32.0 million. Interest expense increased by $14.5 million on the senior notes (including PIK interest) and the credit facility due to an increase in interest rates from the February 2009 amendments to the debt agreements. Additionally the interest rate derivatives yielded an increase of $11.8 million in realized expense due to the decrease in LIBOR rates. Net interest expense consists of the following (in millions):

	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Senior notes	$ 20.9	$ 16.6
PIK Notes	3.6	—
Credit facility	21.8	15.2
Capitalized interest	(1.0)	(2.2)
Mark to market interest rate swaps	(2.4)	(2.2)
Realized interest rate swap losses	14.1	2.3
Interest income	(0.1)	(0.2)
Amortization of debt issue cost	5.6	2.1
Other	2.3	1.2
Total	$ 64.8	$ 32.8

Income Taxes. Income tax expense was $1.2 million for the nine months ended September 30, 2009 compared to $2.1 million for the nine months ended September 30, 2008, a decrease of $0.8 million. The decrease in expense between periods was because the income tax expense for the nine months ended September 30, 2008 included an adjustment of $0.8 million for an unrecognized tax benefit to the Texas margin tax.

Loss on Extinguishment of Debt. We recognized a loss on extinguishment of debt during the nine months ended September 30, 2009 of $4.7 million due to the February 2009 amendment to the senior secured notes agreement. The modifications to this agreement pursuant to this amendment were substantive as defined in FASB ASC 470-50 and were accounted for as the extinguishment of the old debt and the creation of new debt. As a result, the unamortized costs associated with the senior secured notes prior to the amendment as well as the fees paid to the senior secured lenders for the February 2009 amendment were expensed during the nine months ended September 30, 2009.

Other Income. We recorded $7.7 million in other income during the nine months ended September 30, 2008, primarily from the settlement of disputed liabilities that were assumed with an acquisition.

Discontinued Operations. We sold the following non-strategic assets over the past year and used the proceeds from such sales to repay long-term indebtness:

Assets	Date of Sale
12.4% interest in the Seminole Gas Processing Plant	November 2008
Arkoma assets	January 2009
Alabama, Mississippi and south Texas assets	August 2009
Treating assets	October 2009

In accordance with FASB ASC 360-10-05-4, the assets and liabilities and the results of operations related to each of the assets listed above (except the Arkoma assets which were immaterial to the financial statement presentations) were segregated to assets and liabilities held for sale and are presented in income from discontinued operations for the comparative periods in the statements of operations. Revenues, operating expenses, general and administrative expenses associated directly to the assets held for sale, depreciation and amortization, allocated Texas margin tax and allocated interest are reflected in the income from discontinued operations. In August 2009, we expensed $2.0 million of unamortized debt issuance costs associated with the bank credit facility and the senior secured notes due to the repayments of $143.0 million and $69.0 million, respectively, in borrowings from proceeds of the Alabama, Mississippi and south Texas assets disposition. In addition, we incurred make-whole interest and call premiums of $2.4 million in August 2009 to the holders of the senior secured notes due to the call premium on the August repayment. These additional interest costs are included in discontinued operations for the nine months ended September 30, 2009. No corporate office general and administrative expenses have been allocated to income from discontinued operations. Following are the components of revenues and earnings from discontinued operations and operating data (dollars in millions):

	Nine Months Ended September 30,	
	2009	2008
Midstream revenues	$ 368.1	$ 1,437.6
Treating revenues	$ 45.7	$ 56.0
Income from discontinued operations, net of tax	$ 4.4	$ 21.8
Gain from sale of discontinued operations, net of tax (1)	$ 97.4	—
Gathering and Transmission Volumes (MMBtu/d)	564,000	564,000
Processing Volumes (MMBtu/d)	191,000	200,000

(1) Gain on sale of discontinued operations relate to disposition of Alabama, Mississippi and south Texas.

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, 2008.

Liquidity and Capital Resources

As described in "Overview," the economic climate has impacted our sources of liquidity during 2009 leading to declines in our cash flows from operating activities and limiting our ability to access debt and equity markets during the past twelve months. As described in each of the sections below, we have responded to our limited access to capital by reducing our capital expenditures while continuing expansion efforts in our core areas on a more limited basis, by selling non-strategic assets to reduce our long-term indebtedness and by ceasing unit distributions until we meet certain conditions under our long-term debt agreements.

We will use cash flows from operating activities together with our available borrowing capacity under our bank credit facility to fund our capital expenditures for the next twelve months. We believe that the steps we have taken over the past year have improved our position to access debt and equity markets in the coming year.

Cash Flows from Operating Activities. Net cash provided by operating activities was $62.7 million for the nine months ended September 30, 2009 compared to $217.6 million for the nine months ended September 30, 2008. Income before non-cash income and expenses and changes in working capital for comparative periods were as follows (in millions):

	Nine Months Ended September 30,	
	2009	2008
Income before non-cash income and expenses	$ 72.7	$ 125.9
Changes in working capital	$ (10.0)	$ 91.7

The primary reason for the decrease in non-cash income and expense of $53.2 million from 2008 to 2009 relates to increased interest expense of $27.8 million, decreased other income of $7.0 million and decreased margin of $17.4 million. 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 so receivable and payable balances at any month end may fluctuate significantly depending on the timing of these receipts and payments. In addition, although we strive to minimize our natural gas and NGLs 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. Our working capital also includes our mark to market derivative assets and liabilities associated with our derivative cash flow hedges which may fluctuate significantly due to the changes in natural gas and NGL prices. The changes in working capital during the nine months ended September 30, 2008 and 2009 are due to the impact of the fluctuations discussed above and are not indicative of any change in our operating cash flow trends. At September 30, 2008, we had cash on hand of $96.9 million due to the timing of payment releases.

Cash Flows from Investing Activities. Net cash provided by investing activities was $164.2 million and net cash used in investing activities was $214.5 million for the nine months ended September 30, 2009 and 2008, respectively. Our primary investing outflows were capital expenditures for internal growth, net of accrued amounts, as follows (in millions):

	Nine Months Ended September 30,	
	2009	2008
Growth capital expenditures	$ 83.6	$ 205.5
Maintenance capital expenditures	7.2	12.8
Total	$ 90.8	$ 218.3

Net cash invested in Midstream assets was $77.4 million and $178.2 million for the nine months ended September 30, 2009 and 2008, respectively. Net cash invested in Treating assets was $12.2 million for the nine months ended September 30, 2009 and $32.9 million for the nine months ended September 30, 2008. Net cash invested in other corporate assets was $1.2 million for the nine months ended September 30, 2009 and $7.2 million for the nine months ended September 30, 2008.

Cash flows from investing activities for the nine months ended September 30, 2009 and 2008 also includes proceeds from property sales of $245.3 million and $3.8 million, respectively. Proceeds from asset sales for the nine months ending September 30, 2009 consisted primarily of $10.7 million for the Arkoma assets and $214.0 million for the Alabama, Mississippi and south Texas assets. An additional $20.0 million of cash was generated in 2009 by the sale of compressors in north Texas and Louisiana which were leased back through operating leases. The 2008 sales included in continuing operations primarily related to sales of various small Midstream and Treating assets.

Cash Flows from Financing Activities. Net cash used by financing activities was $227.6 million and net cash provided by financing activities was $93.6 million for the nine months ended September 30, 2009 and 2008, respectively. Our financing activities during 2009 primarily related to funding of capital expenditures and repayment of long-term debt and primarily consisted of borrowings under our bank credit facility, borrowings under capital lease obligations, equity offerings and senior note repayments during 2008 as follows (in millions):

	Nine Months Ended September 30,	
	2009	2008
Net borrowings (payments) under bank credit facility (1)	$ (107.5)	$ 118.8
Senior note repayments (2)	(76.0)	(7.1)
Net borrowings (payments) under capital lease obligations	(0.4)	17.6
Debt refinancing costs	(13.8)	(0.4)
Common unit offerings (3)	—	102.0

(1) Includes a $143.0 million payment due to the sale of the Mississippi, Alabama and south Texas assets.

(2) Includes a $69.0 million payment due to sale of the Mississippi, Alabama and south Texas assets.

(3) Includes our general partner’s proportionate contribution and is net of costs associated with the offering costs.

Distributions to unitholders and our general partner until recently have been our primary use of cash in financing activities. Unless prohibited by our bank credit facility, we will distribute available cash, as defined in our partnership agreement, within 45 days after the end of each quarter. Total cash distributions made during the nine months ended September 30, 2009 and 2008 were as follows (in millions):

	Nine Months Ended September 30,	
	2009	2008
Common units	$ 11.4	$ 71.6
Subordinated units	—	2.9
General partner	0.2	33.5
Total	$ 11.6	$ 108.0

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 revolving credit facility. We borrow money under our $1.036 billion credit facility to fund checks as they are presented. As of September 30, 2009, we had approximately $216.6 million of available borrowing capacity under this facility. Our borrowing capacity was reduced to $862.2 million on October 1, 2009 due to the $173.3 million prepayment from proceeds of the Treating assets disposition but the amount available for future borrowing of $216.6 million was unchanged. Changes in drafts payable for the nine months ended 2009 and 2008 were as follows (in millions):

	Nine Months Ended September 30,	
	2009	2008
Decrease in drafts payable	$ 17.9	$ 28.9

Working Capital Deficit. We had a working capital deficit of $29.8 million as of September 30, 2009, primarily due to a net liability for our fair value of derivatives of $15.2 million and accounts and drafts payable of $14.7 million as of the same date. Our fair value of derivatives reflects the mark-to-market of such derivatives including a net current liability of $18.2 million related to interest rate swaps and a net current asset of $3.0 million related to commodity derivatives. As discussed under "Cash Flows" above, in order to reduce our interest costs we do not borrow money to fund outstanding checks until they are presented to our bank.

Off-Balance Sheet Arrangements. We had no off-balance sheet arrangements as of September 30, 2009.

Capital Requirements of the Partnership. We have reduced our budgeted capital expenditures significantly for 2009 to improve our liquidity. The current economic climate and our leveraged position have limited our ability to secure additional funding for growth and expansion projects. Total capital expenditures in the calendar year 2009 are currently anticipated to be approximately $100.0 million and primarily relate to projects in north Texas and Louisiana pursuant to contractual obligations with producers and vendors. We will use cash flow from operations and existing capacity under our bank credit facility to fund our reduced capital spending plan during 2009.

During the nine months ended September 30, 2009, our growth capital expenditures were $83.6 million primarily in north Texas and in north Louisiana. We continued the expansion of our north Louisiana system during 2009 to provide additional compression thereby increasing capacity by 100 MMcf/d to producers in the Haynesville Shale gas play. This project was completed in July 2009 and the total capacity of the north Louisiana system is approximately 375 MMcf/d. We have 10 year firm transportation contracts with four major producers subscribing to all of the incremental capacity on this expansion project. We have contracted additional firm transportation of 35 MMcf/d on our north Louisiana system that is scheduled to come online in November 2009. We have continued our expansion of our north Texas pipeline gathering system in the Barnett Shale on a limited basis during the nine months ended September 30, 2009 to handle volume growth and to connect new wells to our gathering system pursuant to existing obligations with producers. We connected and received initial flow from approximately 72 new wells during the nine months ended September 30, 2009.

We lowered our distribution level to $0.25 per unit for the fourth quarter of 2008 which was paid in February 2009. The amended terms of our credit facility and senior secured note agreement restrict our ability to make distributions unless certain conditions are met. We do not expect that we will meet these conditions in 2009.

Total Contractual Cash Obligations. A summary of our total contractual cash obligations excluding financial and operating data considered discontinued operations as of September 30, 2009 is as follows (in millions):

	Payments Due by Period						
	Total	2009	2010	2011	2012	2013	Thereafter
Long-term debt	$ 1,085.7	$ 260.5	$ 17.6	$ 540.7	$ 93.0	$ 83.6	$ 90.3
Interest payable on fixed long-term debt obligations	110.7	10.4	29.7	26.9	22.0	13.9	7.8
PIK interest payable	19.0	—	—	19.0	—	—	—
Capital lease obligations	28.7	0.8	3.1	3.0	3.0	3.0	15.8
Operating leases	55.0	6.2	13.7	9.8	7.5	5.8	12.0
Unconditional purchase obligations	2.4	2.4	—	—	—	—	—
FIN 48 tax obligations	2.8	2.5	0.1	0.1	0.1	—	—
Total contractual obligations	$ 1,304.3	$ 282.8	$ 64.2	$ 599.5	$ 125.6	$ 106.3	$ 125.9

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The above table does not include any physical or financial contract purchase commitments for natural gas.

Operating leases as presented in the table above no longer include $39.6 million of lease obligations for the Eunice facility. We acquired the Eunice NGL processing plant and fractionation facility on October 15, 2009, and will no longer have the lease obligation to an outside third party.

The current maturity of long-term debt includes the October 2009 paydown of $258.1 million due to proceeds from disposition of Treating assets.

The interest payable under our bank credit facility is not reflected in the above table because such amounts depend on outstanding balances and interest rates which will vary from time to time. Based on balances outstanding and rates in effect at September 30, 2009, annual interest payments would be $45.7 million. The interest amounts also exclude estimates of the effect of our interest rate swap contracts.

The unconditional purchase obligations for 2009 relate to purchase commitments for equipment.

Indebtedness

As of September 30, 2009 and December 31, 2008, long-term debt consisted of the following (in millions):

	September 30, 2009	December 31, 2008
Bank credit facility, interest based on Prime and/or LIBOR plus an applicable margin, interest rates (per the facility) at September 30, 2009 and December 31, 2008 were 6.75% and 3.9%, respectively	$ 676.5	$ 784.0
Senior secured notes (including PIK notes of $5.5 million), weighted average interest rates at September 30, 2009 and December 31, 2008 were 10.5% and 8.0%, respectively	409.2	479.7
	1,085.7	1,263.7
Less current portion	(21.3)	(9.4)
Debt classified as long-term	$ 1,064.4	$ 1,254.3

On October 1, 2009, proceeds from the disposition of the Treating assets as discussed in Note 2 were used to prepay $173.3 million of bank borrowings and $84.8 million of senior secured note borrowings.

As of September 30, 2009, we had a bank credit facility with a borrowing capacity of $1.036 billion that matures in June 2011. As of September 30, 2009, $818.9 million was outstanding under the bank credit facility, including $142.4 million of letters of credit, leaving approximately $216.6 million available for future borrowing. Our borrowing capacity was reduced to $862.2 million on October 1, 2009 due to the $173.3 million prepayment from proceeds of the Treating assets disposition but the amount available for future borrowing of $216.6 million was unchanged. The bank credit facility is guaranteed by certain of our subsidiaries.

Our bank credit facility has satisfied a leverage fee payment requirement that would have triggered if we had not prepaid debt and permanently reduce the banks' commitments and senior secured note borrowings by the cumulative amounts of $100.0 million on September 30, 2009, $200.0 million on December 31, 2009 and $300.0 million on March 31, 2010. In order to avoid this fee, we reduced our bank commitments and senior secured note borrowings by $212.0 million in August 2009 with proceeds from the disposition of Alabama, Mississippi and south Texas assets and by $258.1 million with proceeds from the disposition of Treating assets in October 1, 2009. These payments satisfied the de-leveraging targets for September and December 2009 and March 2010. As of October 2009, after giving effect to these repayments of long-term debt and the reduction of commitments under our bank credit facility as a result of such repayments, we had a bank credit facility with a borrowing capacity of $862.2 million and $327.8 million (including PIK) of outstanding senior secured notes.

Recent Accounting Pronouncements

FASB ASC 805 and FASB ASC 810-10-65-1 were issued December 2007. FASB ASC 805 requires most identifiable assets, liabilities, non-controlling interests and goodwill acquired in a business combination to be recorded at “full fair value.” The Statement applies to all business combinations, including combinations among mutual entities and combinations by contract alone. Under FASB ASC 805, all business combinations will be accounted for by applying the acquisition method. FASB ASC 805 is effective for periods beginning on or after December 15, 2008. FASB ASC 810-10-65-1 requires non-controlling interests (previously referred to as minority interests) to be treated as a separate component of equity, not as a liability or other item outside of permanent equity. FASB ASC 810-10-65-1 was adopted January 1, 2009 and comparative period information has been recast to classify non-controlling interests in equity and attribute net income and other comprehensive income to non-controlling interests.

FASB ASC 815-10-65-1 was issued in March 2008, and requires entities to provide greater transparency about how and why the entity uses derivative instruments, how the instruments and related hedged items are accounted for under FASB ASC 815 and how the instruments and related hedged items affect the financial position, results of operations and cash flows of the entity. FASB ASC 815-10-65-1 is effective for fiscal years beginning after November 15, 2008. FASB ASC 815-10-65-1 was adopted effective January 1, 2009 and we added the required disclosures.

FASB ASC 105 was released July 1, 2009 and intended to improve financial reporting by identifying a consistent framework, or hierarchy, for selecting accounting principles to be used in preparing financial statements of non-governmental entities that are presented in conformity with generally accepted accounting principles (GAAP) in the United States of America. SFAS No. 162 has been superseded by SFAS No. 168, “The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles” (the Codification) released July 1, 2009. The Codification became the exclusive authoritative reference for non-governmental U.S. GAAP for use in financial statements issued for interim and annual periods ending after September 15, 2009, except for Securities and Exchange Commission (SEC) rules and interpretive releases, which are also authoritative GAAP for SEC registrants. The change establishes non-governmental U.S. GAAP into the authoritative Codification and guidance that is nonauthoritative. The contents of the Codification carry the same level of authority, eliminating the four-level GAAP hierarchy previously set forth in Statement 162. The Codification supersedes all existing non-SEC accounting and reporting standards. All other non-grandfathered, non-SEC accounting literature not included in the Codification has become nonauthoritative. We have revised all GAAP references to reflect the Codification for the quarter ending September 30, 2009.

FASB ASC 260-10-45-60 was issued in June 2008 and requires unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents to be treated as *participating securities* as defined in FASB ASC 260-10-20 and, therefore, included in the earnings allocation in computing earnings per share under the two-class method described in FASB ASC 260. FASB ASC 260-10-45-60 is effective for financial statements issued for fiscal years beginning after December 15, 2008 and interim periods within those years. We adopted FASB ASC 260-10-45-60 effective January 1, 2009 and adjusted all prior reporting periods to conform to the requirements.

In addition, FASB ASC 260-10-55-102 addresses the consensus reached by the Task Force that incentive distribution rights (IDRs) in a typical master limited partnership are participating securities under FASB ASC 260, but earnings in excess of the partnership’s “available cash” should not be allocated to the IDR holders for purposes of calculating earnings-per-share using the two-class method when “available cash” represents a specified threshold that limits participation. The consensus only applies when payments to IDR holders are accounted for as equity distributions. The consensus is effective for fiscal years beginning after December 15, 2008 and applied retrospectively to all periods presented. Under our partnership agreement, “available cash” is a specified threshold that limits participation for IDR holders. Therefore earnings in excess of our “available cash” during the three and nine months ended September 30, 2009 were not allocated to IDR holders.

In June 2009 FASB ASC 810-10-05-8 was issued. It requires reporting entities to evaluate former Qualifying Special Purpose Entities or QSPEs for consolidation, changes the approach to determining a variable interest entity's (VIE) primary beneficiary from a quantitative assessment to a qualitative assessment designed to identify a controlling financial interest, and increases the frequency of required reassessments to determine whether a company is the primary beneficiary of a VIE. It also clarifies, but does not significantly change, the characteristics that identify a VIE. This Statement requires additional year-end and interim disclosures for public and nonpublic companies that are similar to the disclosures required by FASB ASC 860-10-65-2. The Statement is effective for fiscal years beginning after November 15, 2009 and for subsequent interim and annual reporting periods. We do not expect this statement to have a significant impact on our financial statements.

FASB ASC 855 was issued in June 2009 and is effective for interim or annual financial periods ending after June 15, 2009 and addresses accounting and disclosure requirements related to subsequent events. The statement requires management to evaluate subsequent events through the date the financial statements are issued. Companies are required to disclose the date through which subsequent events have been evaluated. We have taken this statement into consideration.

FASB ASC 825-10-65-1 requires publicly traded companies to disclose the fair value of financial instruments within the scope of FASB ASC 825 in interim financial statements, adding to the current requirement to make those disclosures in annual financial statements. FASB ASC 825-10-65-1 is effective for interim and annual periods ending after June 15, 2009. We have added the required footnote disclosure.

Disclosure Regarding Forward-Looking Statements

This Quarterly Report on Form 10-Q includes "forward-looking statements" within the meaning of the federal securities laws that are based on information currently available to management as well as management's assumptions and beliefs. 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, 2008, 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.

Interest Rate Risk

We are exposed to interest rate risk on our variable rate bank credit facility. At September 30, 2009, our bank credit facility had outstanding borrowings of $676.5 million which approximated fair value. We manage a portion of our interest rate exposure on our variable rate debt by utilizing interest rate swaps, which allow us to convert a portion of variable rate debt into fixed rate debt. In January 2008, we amended our existing interest rate swaps covering $450.0 million of the variable rate debt to extend the period by one year (coverage periods end from November 2010 through October 2011) and reduce the interest rates to a range of 4.38% to 4.68%. In September 2008, we entered into additional interest rate swaps covering the $450.0 million that converted the floating rate portion of the original swaps from three month LIBOR to one month LIBOR. As of September 30, 2009, the fair value of these interest rate swaps was reflected as a liability of $28.0 million ($18.2 million in net current liabilities and $9.8 million in long-term liabilities) on our financial statements. We estimate that a 1% increase or decrease in the interest rate would increase or decrease the fair value of these interest rate swaps by approximately $14.8 million. Considering the interest rate swaps and the amount outstanding on our bank credit facility as of September 30, 2009, we estimate that a 1% increase or decrease in the interest rate would change our annual interest expense by approximately $2.3 million for annual periods when the entire portion of the $450.0 million of interest rate swaps are outstanding and $6.8 million for annual periods after 2011 when all the interest rate swaps lapse.

At September 30, 2009, we had total fixed rate debt obligations of $409.2 million, consisting of our senior secured notes (including PIK) with a weighted average interest rate of 10.5%. The fair value of these fixed rate obligations was approximately $392.1 million as of September 30, 2009. We estimate that a 1% increase or decrease in interest rates would increase or decrease the fair value of the fixed rate debt (our senior secured notes including PIK) by $10.8 million based on the debt obligations as of September 30, 2009.

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") in processing. 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 our margins are negative under our current processing margin contracts 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 treated or conditioned.

The gross margin presentation in the table below is calculated net of results from discontinued operations. Gas processing margins by contract type and gathering and transportation margins as a percent of total gross margin for the comparative quarterly and year-to-date periods are as follows:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
Gathering and transportation margin	63.8%	42.2%	67.1%	51.5%
Gas processing margins:				
Processing margin	10.6%	26.4%	8.0%	19.7%
Percent of liquids	12.8%	24.2%	12.8%	20.2%
Fee based	12.8%	7.2%	12.1%	8.6%
Total gas processing	36.2%	57.8%	32.9%	48.5%
Total	100.0%	100.0%	100.0%	100.0%

We have hedges in place at September 30, 2009 covering liquids volumes we expect to receive under percent of liquids (POL) contracts as set forth in the following tables. The relevant payment index price is the monthly average of the daily closing price for deliveries of commodities into Mont Belvieu, Texas as reported by the Oil Price Information Service (OPIS).

Period	Underlying	Notional Volume	We Pay	We Receive*	Fair Value Asset/(Liability) (In thousands)
October 2009-December 2009	Ethane	34 (MBbls)	Index	$0.6401/gal	$ 180
October 2009-December 2009	Propane	27 (MBbls)	Index	$1.2771/gal	369
October 2009-December 2009	Iso Butane	5 (MBbls)	Index	$1.7179/gal	120
October 2009-December 2009	Normal Butane	10 (MBbls)	Index	$1.5320gal	146
October 2009-December 2009	Natural Gasoline	20 (MBbls)	Index	$2.0257/gal	502
					$ 1,317

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Period	Underlying	Notional Volume	We Pay	We Receive*	Fair Value Asset/(Liability) (In thousands)
January 2010 – December 2010	Propane	109 (MBbls)	Index	$0.9584/gal	$ 5
January 2010 – December 2010	Normal Butane	40 (MBbls)	Index	$1.2580/gal	93
January 2010 – December 2010	Natural Gasoline	21 (MBbls)	Index	$1.4815/gal	14
					$ 112

* 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 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 66.3% of our hedgeable volumes at risk through the end of 2009 (37.2% of total volumes at risk through the end of 2009). We have also hedged 46.5% of our hedgeable natural gasoline volumes for 2010 (17.9% of total natural gasoline volumes at risk for 2010).

We also have hedges in place at September 30, 2009 covering the fractionation spread risk related to our processing margin contracts as set forth in the following table:

Period	Underlying	Notional Volume	We Pay	We Receive	Fair Value Asset/(Liability) (In thousands)
October 2009 – December 2009	Ethane	39 (MBbls)	Index	$0.44/gal*	$ (118)
October 2009 – December 2009	Propane	24 (MBbls)	Index	$0.8148/gal*	(137)
October 2009 – December 2009	Iso-Butane	1 (MBbls)	Index	$1.105/gal*	(2)
October 2009 – December 2009	Normal Butane	15 (MBbls)	Index	$1.0263/gal*	(108)
October 2009 – December 2009	Natural Gasoline	16 (MBbls)	Index	$1.385/gal*	(29)
October 2009 – December 2009	Natural Gas	4,822 (MMBtu/d)	$4.8225/MMBtu*	Index	32
					$ (362)

Period	Underlying	Notional Volume	We Pay	We Receive	Fair Value Asset/(Liability) (In thousands)
January 2010 – December 2010	Ethane	127 (MBbls)	Index	$0.4607/gal*	$ (307)
January 2010 – December 2010	Propane	85 (MBbls)	Index	$0.9226/gal*	(116)
January 2010 – December 2010	Normal Butane	57 (MBbls)	Index	$1.2007gal*	(1)
January 2010 – December 2010	Natural Gasoline	56 (MBbls)	Index	$1.5305/gal*	140
January 2010 – December 2010	Natural Gas	4,269 (MMbtu/d)	$5.7672/MMBtu*	Index	617
					$ 333

* weighted average

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. Less than 3.0% 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. As a result of purchasing the natural gas at a percentage of the index price, our resale margins are higher during periods of high natural gas prices and lower during periods of lower natural gas prices. We have hedged 36.6% of our natural gas volumes at risk through the end of 2009.

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.

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

As of September 30, 2009, 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 $4.7 million. The aggregate effect of a hypothetical 10% increase in gas and NGL prices would result in a decrease of approximately $1.8 million in the net fair value asset of these contracts as of September 30, 2009.

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 concluded that our disclosure controls and procedures were effective as of September 30, 2009 in alerting them in a timely manner to material information required to be disclosed in our reports filed with the Securities and Exchange Commission.

(b) Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting that occurred in the three months ended September 30, 2009 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 11, “Commitments and Contingencies,” of the Notes to Consolidated Consolidated Financial Statements, which is incorporated by reference herein.

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

Information about risk factors for the three months ended September 30, 2009 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, 2008.

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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†	—	Partnership Interest Purchase and Sale Agreement, dated as of June 9, 2009, among Crosstex Energy Services, L.P., Crosstex Energy Services GP, LLC, Crosstex CCNG Gathering, Ltd., Crosstex CCNG Transmission Ltd., Crosstex Gulf Coast Transmission Ltd., Crosstex Mississippi Pipeline, L.P., Crosstex Mississippi Gathering, L.P., Crosstex Mississippi Industrial Gas Sales, L.P., Crosstex Alabama Gathering System, L.P., Crosstex Midstream Services, L.P., Javelina Marketing Company Ltd., Javelina NGL Pipeline Ltd. and Southcross Energy LLC (incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K dated June 9, 2009, filed with the Commission on June 11, 2009).
2.2†	—	Partnership Interest Purchase and Sale Agreement, dated as of August 28, 2009, among Crosstex Energy Services, L.P., Crosstex Energy Services GP, LLC, Crosstex Treating Services, L.P. and KM Treating GP LLC (incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K dated August 28, 2009, filed with the Commission on September 3, 2009).
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	—	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).
3.3	—	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).
3.4	—	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).
3.5	—	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).
3.6	—	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. 0-50067).
3.7	—	Certificate of Limited Partnership of Crosstex Energy GP, L.P. (incorporated by reference to Exhibit 3.5 to our Registration Statement on Form S-1, file No. 333-97779).
3.8	—	Agreement of Limited Partnership of Crosstex Energy GP, L.P., dated as of July 12, 2002 (incorporated by reference to Exhibit 3.6 to our Registration Statement on Form S-1, file No. 333-97779).
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).
31.1*	—	Certification of the Principal Executive Officer.
31.2*	—	Certification of the Principal Financial Officer.
32.1*	—	Certification of the Principal Executive Officer and Principal Financial Officer of the Company pursuant to 18 U.S.C. Section 1350.

* Filed herewith.

† In accordance with the instructions to Item 601(b)(2) of Regulation S-K, the exhibits and schedules to Exhibits 2.1 and 2.2 are not filed herewith. The agreements identify such exhibits and schedules, including the general nature of their content. We undertake to provide such exhibits and schedules to the Commission 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, L.P.,
its general partner

By: Crosstex Energy GP, LLC,
its general partner

By: /s/ William W. Davis
William W. Davis
Executive Vice President and
Chief Financial Officer

November 6, 2009

EXHIBIT INDEX

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* Filed herewith.

† In accordance with the instructions to Item 601(b)(2) of Regulation S-K, the exhibits and schedules to Exhibits 2.1 and 2.2 are not filed herewith. The agreements identify such exhibits and schedules, including the general nature of their content. We undertake to provide such exhibits and schedules to the Commission upon request.

Exhibit 31.1

CERTIFICATIONS

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

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

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

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

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

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

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

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

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

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

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

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

/s/ Barry E. Davis
Barry E. Davis,
President and Chief Executive Officer
(principal executive officer)

Date: November 6, 2009

Exhibit 31.2

CERTIFICATIONS

I, William W. Davis, Executive Vice President and Chief Financial Officer of Crosstex Energy GP, LLC, the general partner of Crosstex Energy GP, L.P., 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/ William W. Davis
William W. Davis,
Executive Vice President and Chief Financial Officer
(principal financial and accounting officer)

Date: November 6, 2009

Exhibit 32.1

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

In connection with the Quarterly Report of Crosstex Energy, L.P. (the "Registrant") on Form 10-Q for the quarter ended September 30, 2009 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 William W. Davis, Chief Financial Officer of Crosstex Energy GP, LLC, certifies, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

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

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

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

November 6, 2009

/s/ William W. Davis
William W. Davis
Chief Financial Officer

November 6, 2009

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.