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

Form 10-Q

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

for the quarterly period ended June 30, 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 registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

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

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

As of July 28, 2009, the Registrant had 49,068,645 common units outstanding.

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CROSSTEX ENERGY, L.P.

Condensed Consolidated Balance Sheets

	June 30, 2009 (Unaudited)	December 31, 2008
	(In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 869	$ 1,636
Accounts and notes receivable, net:		
Trade, accrued revenue and other	211,098	353,364
Related party	30	110
Fair value of derivative assets	8,196	27,166
Natural gas and natural gas liquids, prepaid expenses and other	15,205	9,645
Assets held for sale	169,345	¾
Total current assets	404,743	391,921
Property and equipment, net of accumulated depreciation of $257,097 and $296,393, respectively	1,415,454	1,527,280
Fair value of derivative assets	7,553	4,628
Intangible assets, net of accumulated amortization of $107,845 and $89,231, respectively	559,483	578,096
Goodwill	19,673	19,673
Other assets, net	16,951	11,668
Total assets	$ 2,423,857	$ 2,533,266
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable, drafts payable and accrued gas purchases	$ 143,537	$ 322,722
Fair value of derivative liabilities	21,696	28,506
Current portion of long-term debt	24,412	9,412
Other current liabilities	60,182	64,191
Liabilities of assets held for sale	46,876	¾
Total current liabilities	296,703	424,831
Long-term debt	1,318,637	1,254,294
Obligations under capital lease	24,608	24,708
Deferred tax liability	8,310	8,727
Fair value of derivative liabilities	18,372	22,775
Commitments and contingencies	¾	¾
Partners' equity including non-controlling interest	757,227	797,931
Total liabilities and equity	$ 2,423,857	$ 2,533,266

See accompanying notes to condensed consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Operations

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(Unaudited) (In thousands, except per unit amounts)			
Revenues:				
Midstream	$ 347,820	$ 996,000	$ 700,257	$ 1,794,902
Treating	13,892	11,647	28,204	22,727
Profit on energy trading activities	1,427	828	2,141	1,684
Total revenues	363,139	1,008,475	730,602	1,819,313
Operating costs and expenses:				
Midstream purchased gas	270,845	916,776	555,351	1,634,360
Operating expenses	32,661	33,740	64,589	70,082
General and administrative	14,129	17,313	28,342	32,768
(Gain) loss on sale of property	284	(1,381)	(594)	(1,641)
Gain on derivatives	(715)	(844)	(5,051)	(1,830)
Depreciation and amortization	33,748	29,118	65,313	58,000
Total operating costs and expenses	350,952	994,722	707,950	1,791,739
Operating income	12,187	13,753	22,652	27,574
Other income (expense):				
Interest expense, net	(26,111)	(2,005)	(48,400)	(26,567)
Loss on extinguishment of debt	¾	¾	(4,669)	¾
Other income	171	475	121	7,579
Total other income (expense)	(25,940)	(1,530)	(52,948)	(18,988)
Income (loss) from continuing operations before non-controlling interest and income taxes	(13,753)	12,223	(30,296)	8,586
Income tax provision	(592)	(326)	(1,150)	(669)
Income (loss) from continuing operations, net of tax	(14,345)	11,897	(31,446)	7,917
Income from discontinued operations	4,036	9,895	5,831	17,730
Net income (loss)	(10,309)	21,792	(25,615)	25,647
Less: Net income from continuing operations attributable to the non-controlling interest	9	50	41	194
Net income (loss) attributable to Crosstex Energy, L.P.	$ (10,318)	$ 21,742	$ (25,656)	$ 25,453
General partner interest in net income (loss) including incentive distribution rights	$ (951)	$ 11,401	$ (1,891)	$ 22,051
Limited partners’ interest in net income (loss) attributable to Crosstex Energy, L.P.	$ (9,367)	$ 10,341	$ (23,765)	$ 3,402
Net income (loss) attributable to Crosstex Energy, L.P. per limited partners’ unit:				
Basic common unit	$ (0.19)	$ 0.23	$ (1.22)	$ (2.92)
Diluted common unit	$ (0.19)	$ 0.21	$ (1.22)	$ (2.92)
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.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Changes in Partners' Equity
Six Months Ended June 30, 2009

	Common Units		Sr. Subordinated D Units		General Partner Interest		Accumulated Other Comprehensive Income (loss)	Non-Controlling Interest	Total
	$	Units	$	Units	$	Units			
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	(70)	80	¾	¾	¾	¾	¾	¾	(70)
Capital contributions	¾	¾	¾	¾	9	5	¾	¾	9
Stock-based compensation	2,466	¾	¾	¾	1,456	¾	¾	¾	3,922
Distributions	(11,368)	¾	¾	¾	(229)	¾	¾		(11,597)
Net income (loss)	(23,765)	¾	¾	¾	(1,891)	¾	¾	41	(25,615)
Hedging gains or losses reclassified to earnings	¾	¾	¾	¾	¾	¾	(5,860)	¾	(5,860)
Adjustment in fair value of derivatives	¾	¾	¾	¾	¾	¾	(1,265)	¾	(1,265)
Distribution to non-controlling interest	¾	¾	¾	¾	¾	¾	¾	(228)	(228)
Balance, June 30, 2009	$ 741,769	49,058	$ ¾	¾	$ 16,150	1,001	$ (4,015)	$ 3,323	$ 757,227

(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 June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(Unaudited) (In thousands)			
Net income (loss)	$ (10,309)	$ 21,792	$ (25,615)	$ 25,647
Hedging gains (losses) reclassified to earnings	(1,660)	6,035	(5,860)	11,583
Adjustment in fair value of derivatives	(954)	(19,225)	(1,265)	(30,279)
Comprehensive income (loss)	$ (12,923)	$ 8,602	$ (32,740)	$ 6,951
Comprehensive income attributable to non-controlling interest	9	50	41	194
Comprehensive income and (loss) attributable to Crosstex Energy, L.P.	$ (12,932)	$ 8,552	$ (32,781)	$ 6,757

See accompanying notes to condensed consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Cash Flows

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(Unaudited) (In thousands)	
Cash flows from operating activities:		
Net income (loss)	$ (25,615)	$ 25,647
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation and amortization	68,468	65,242
Gain on sale of property	(595)	(1,659)
Deferred tax (benefit) expense	(418)	(127)
Non-cash stock-based compensation	3,922	6,366
Non-cash derivatives gain	(2,881)	(6,021)
Non-cash loss on debt extinguishment	4,669	¾
Interest paid-in-kind	2,066	¾
Amortization of debt issue costs	3,483	1,387
Changes in assets and liabilities:		
Accounts receivable, accrued revenue and other	85,856	(249,659)
Natural gas and natural gas liquids, prepaid expenses and other	(6,686)	(18,449)
Accounts payable, accrued gas purchases and other accrued liabilities	(113,228)	263,905
Net cash provided by operating activities	19,041	86,632
Cash flows from investing activities:		
Additions to property and equipment	(74,968)	(151,251)
Insurance recoveries on property and equipment	8,107	¾
Proceeds from sale of property	10,735	3,769
Net cash used in investing activities	(56,126)	(147,482)
Cash flows from financing activities:		
Proceeds from borrowings	359,200	717,300
Payments on borrowings	(281,156)	(686,006)
Proceeds from capital lease obligations	1,489	12,258
Payments on capital lease obligations	(1,397)	(405)
Decrease in drafts payable	(16,497)	(10,540)
Debt refinancing costs	(13,435)	(233)
Conversion of restricted units, net of units withheld for taxes	(70)	(1,298)
Distributions to non-controlling interest	(228)	¾
Distribution to partners	(11,597)	(66,206)
Proceeds from exercise of unit options	¾	672
Common unit offering costs	¾	99,928
Contributions from partners	9	2,174
Contributions from non-controlling interest	¾	109
Net cash provided by financing activities	36,318	67,753
Net increase (decrease) in cash and cash equivalents	(767)	6,903
Cash and cash equivalents, beginning of period	1,636	142
Cash and cash equivalents, end of period	$ 869	$ 7,045
Cash paid for interest	$ 38,303	$ 37,070
Cash paid for income taxes	$ 1,220	$ 1,102

See accompanying notes to condensed consolidated financial statements.

(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, treating, 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, treats natural gas to remove impurities to ensure that it meets pipeline quality specifications, 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

In December 2007, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 141R, *"Business Combinations"* (SFAS 141R) and SFAS No. 160, *"Non-controlling Interests in Consolidated Financial Statements"* (SFAS 160). SFAS 141R 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 SFAS 141R, all business combinations will be accounted for by applying the acquisition method. SFAS 141R is effective for periods beginning on or after December 15, 2008. SFAS 160 will require 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. SFAS 160 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 noncontrolling interests.

In March 2008, the FASB issued SFAS No. 161, *"Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133"* (SFAS 161). SFAS 161 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 SFAS 133, and how the instruments and related hedged items affect the financial position, results of operations and cash flows of the entity. SFAS 161 is effective for fiscal years beginning after November 15, 2008. SFAS 161 was adopted effective January 1, 2009. Required disclosures were added to Note 7.

In May 2008, the FASB issued SFAS No. 162, "*The Hierarchy of Generally Accepted Accounting Principles"* (SFAS 162) with an effective date of January 1, 2009. SFAS 162 was intended to improve financial reporting by identifying a consistent framework, or hierarchy, for selecting accounting principles to be used in preparing financial statements of nongovernmental entities that are presented in conformity with generally accepted accounting principles in the United States of America. SFAS 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 will become the exclusive authoritative reference for nongovernmental 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 nongovernmental U.S. GAAP into the authoritative Codification and guidance that is nonauthoritative. The contents of the Codification will carry the same level of authority, eliminating the four-level GAAP hierarchy previously set forth in Statement 162. The Codification will supersede all existing non-SEC accounting and reporting standards. All other non-grandfathered, non-SEC accounting literature not included in the Codification will become nonauthoritative. The Partnership will be revising all GAAP references to reflect the Codification for the quarter ending September 30, 2009.

In June 2008, the FASB issued Staff Position FSP EITF 03-6-1 (the FSP) which 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 EITF Issue No. 03-6, *"Participating Securities and the Two-Class Method under FASB Statement No. 128,"* and, therefore, included in the earnings allocation in computing earnings per share under the two-class method described in FASB Statement No. 128, *"Earnings per Share."* The FSP is effective for financial statements issued for fiscal years beginning after December 15, 2008 and interim periods within those years. The Partnership adopted the FSP effective January 1, 2009 and adjusted all prior reporting periods to conform to the requirements.

In addition, the FASB issued EITF 07-4, *"Application of the Two-Class Method under FASB Statement No. 128, Earnings per Share, to Master Limited Partnerships*" which addresses the consensus reached by the Task Force that incentive distribution rights (IDRs) in a typical master limited partnership are participating securities under FASB Statement No. 128, "*Earnings per Share*," 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. Currently this EITF has no impact on the Partnership's earnings per unit calculations.

In June 2009, the FASB issued SFAS No. 167, "*Amendments to FASB Interpretation No. 46(R) (SFAS 167)."* SFAS 167 amends the guidance in FASB Interpretation 46R related to the consolidation of variable interest entities or VIEs. It requires reporting entities to evaluate former Qualifying Special Purpose Entities or QSPEs for consolidation, changes the approach to determining a VIE's 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 FSP FAS 140-4 and FIN 46(R)-8, "*Disclosures by Public Entities (Enterprises) about Transfers of Financial Assets and Interests in Variable Interest Entities*." 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.

In June 2009, the FASB issued FASB Statement No. 165, "*Subsequent Events,*" that 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.

The FASB recently issued Staff Position FSP FAS 107-1 and APB 28-1, "*Interim Disclosures about Fair Value of Financial Instruments*," requiring publicly traded companies, as defined in Opinion 28, to disclose the fair value of financial instruments within the scope of FASB Statement No. 107, "*Disclosures about Fair Value of Financial Instruments*," in interim financial statements, adding to the current requirement to make those disclosures in annual financial statements. The Staff Position is effective for interim and annual periods ending after June 15, 2009. The Partnership has added the required footnote disclosure.

(2) Assets Held for Sale and Asset Disposition

As part of the Partnership's strategy to increase liquidity in response to the tightening financial markets, the Partnership has sold and is also marketing for sale certain non-strategic assets.

During the six months ended June 30, 2009 the Partnership sold the Arkoma system to an unrelated third party for approximately $10.6 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 six months ended June 30, 2009 was $0.4 million.

In addition to the sale of the Arkoma system, the Partnership entered into an agreement in May 2009 to sell its assets in Mississippi, Alabama and south Texas for $220.0 million. The sale closed on August 6, 2009 and the Partnership recognized a gain of approximately $98.0 million. Sales proceeds, net of transaction costs and other obligations associated with the sale, of $212.0 million were used to repay long-term debt. In accordance with SFAS No. 144, "*Accounting for the Impairment or Disposal of Long-Lived Assets*," the consolidated balance sheet at June 30, 2009 reflects these assets as held for sale. The assets and liabilities consisted of the following as of June 30, 2009 (in thousands):

Midstream	
Current assets	$ 53,029
Property and equipment	110,029
Current liabilities	(46,477)
Net book value	$ 116,581
Treating	
Current assets	$ 272
Property and equipment	6,015
Current liabilities	(399)
Net book value	$ 5,888
Total assets held for sale	$ 122,469

The revenues, operating expenses, depreciation and amortization expense 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. No income taxes are attributed to income from discontinued operations and no 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 June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Midstream revenues	$ 134,526	$ 528,392	$ 313,726	$ 981,671
Treating revenues	$ 1,578	$ 6,344	$ 3,542	$ 11,606
Net income from discontinued operations	$ 4,036	$ 9,895	$ 5,831	$ 17,730

(3) Long-Term Debt

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

	June 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 June 30, 2009 and December 31, 2008 were 6.75% and 3.9%, respectively	$ 866,750	$ 784,000
Senior secured notes (including PIK notes as defined below of $1.3 million), weighted average interest rate at June 30, 2009 and December 31, 2008 were 10.5% and 8.0%, respectively	476,299	479,706
	1,343,049	1,263,706
Less current portion	(24,412)	(9,412)
Debt classified as long-term	$ 1,318,637	$ 1,254,294

Credit Facility. As of June 30, 2009, the Partnership had a bank credit facility with a borrowing capacity of $1.181 billion that matures in June 2011. As of June 30, 2009, $981.2 million was outstanding under the bank credit facility, including $114.4 million of letters of credit, leaving approximately $199.8 million available for future borrowing.

CROSSTEX ENERGY, L.P.

Notes to Condensed Consolidated Financial Statements — (Continued)

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 first half of 2009 have been at the high end of these ranges and, based on the Partnership's forecasted leverage ratios for the last half of 2009, it expects the applicable margins to be at the high end of these ranges for its interest rate and LC fees.

Pursuant to the Sixth Amendment, the Partnership must pay a leverage fee if it does 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. If it fails to meet any de-leveraging target, it must pay a leverage fee equal to the product of the aggregate commitments outstanding under our bank credit facility and the outstanding amounts of the senior secured note agreement on such date, and 1.0% on September 30, 2009, 1.0% on December 31, 2009 and 2.0% on March 31, 2010. This leverage fee will accrue on the applicable date, but not be payable until the Partnership refinances its bank credit facility. The disposition of Mississippi, Alabama and south Texas assets that closed on August 6, 2009 satisfied the September 30, 2009 and December 31, 2009 de-leveraging targets.

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 quarters ending June 30, 2009 and 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:

- 1.50 to 1.00 for the fiscal quarter ending June 30, 2009;
- 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). The Partnership does not intend to make any acquisitions during 2009.

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 our 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 us 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 six months ended June 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 EITF Issue No. 96-19, "*Debtor's Accounting for a Modification or Exchange of Debt Instruments*" 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 six months ended June 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%.

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 our bank credit facility.

The Partnership was in compliance with all debt covenants as of June 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 our 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 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 our bank credit facility, holders of our senior secured notes and the other parties thereto in respect of the collateral securing the Partnership's obligations under our 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 9 and 10-year capital leases for certain equipment. Assets under capital leases as of June 30, 2009 are summarized as follows (in thousands):

Equipment	$ 30,577
Less: Accumulated amortization	(2,907)
Net assets under capital lease	$ 27,670

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

2009	$ 1,564
2010	3,437
2011 through 2013 ($3,409 annually)	10,227
Thereafter	17,689
Less: Interest	(4,930)
Net minimum lease payments under capital lease	27,987
Less: Current portion of net minimum lease payments	(3,379)
Long-term portion of net minimum lease payments	$ 24,608

(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 our general partner is entitled to 13.0% of amounts we distribute in excess of $0.25 per unit, 23.0% of the amounts we distribute in excess of $0.3125 per unit and 48.0% of amounts we distribute in excess of $0.375 per unit. No incentive distributions were earned by our general partner for the three and six months ended June 30, 2009. Incentive distributions totaling $12.3 million and $24.1 million were earned by our general partner for the three and six months ended June 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 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 subordination period. These discounts represent beneficial conversion features (BCFs) under EITF 98-5: *"Accounting for Convertible Securities with Beneficial Conversion Features or Contingently Adjustable Conversion Ratios."* Under EITF 98-5 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

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FSP EITF 03-6-1, "*Determining Whether Instruments Granted in Share-Based Payment Transactions are Participating Securities*", was issued in May 2008 with an effective date for fiscal years beginning after December 15, 2008 and interim periods within those years. This FSP requires unvested share-based payments that entitle employees to receive non-forfeitable distributions to also be considered participating securities, as defined in EITF 03-6. The Partnership was impacted by this EITF and has calculated earnings attributable to unvested restricted units and adjusted earnings per unit calculations for the three and six months ended June 30, 2009 and the comparative three and six months ended June 30, 2008 to reflect implementation of the EITF.

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 June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Limited partners' interest in net income (loss)	$ (9,367)	$ 10,341	$ (23,765)	$ 3,402
Distributed earnings allocated to:				
Common units (1)	$ ¾	$ 27,781	$ 11,234	$ 45,249
Unvested restricted units	¾	310	134	534
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	$ 28,091	$ 45,665	$ 166,895
Undistributed loss allocated to:				
Common units (5)	$ (9,152)	$ (17,519)	$ (68,623)	$ (161,407)
Unvested restricted units (5)	(215)	(231)	(807)	(2,086)
Senior subordinated series C units	¾	¾	¾	¾
Senior subordinated series D units	¾	¾	¾	¾
Total undistributed earnings (loss)	$ (9,367)	$ (17,750)	$ (69,430)	$ 163,493
Net income (loss) allocated to:				
Common units	$ (9,152)	$ 10,262	$ (57,389)	$ (116,158)
Unvested restricted units	(215)	79	(673)	(1,552)
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)	$ (9,367)	$ 10,341	$ (23,765)	$ 3,402
Limited partners' interest in income from discontinued operations:				
Common units(4)	$ 3,865	$ 9,571	$ 5,608	$ 17,151
Unvested restricted units	91	126	107	224
Senior subordinated series C and D units	¾	¾	¾	¾
Total income from discontinued operations	$ 3,956	$ 9,697	$ 5,715	$ 17,375
Basic and diluted net income (loss) per unit from continuing operations:				
Basic common unit	$ (0.27)	$ 0.02	$ (1.34)	$ (3.35)
Diluted common unit	$ (0.27)	$ 0.01	$ (1.34)	$ (3.35)
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	$ 0.08	$ 0.22	$ 0.12	$ 0.43
Diluted common unit	$ 0.08	$ 0.20	$ 0.12	$ 0.43
Senior subordinated series C and D unit	$ ¾	$ ¾	$ ¾	$ ¾
Total basic and diluted net income (loss) per unit:				
Basic common unit	$ (0.19)	$ 0.23	$ (1.22)	$ (2.92)
Diluted common unit	$ (0.19)	$ 0.21	$ (1.22)	$ (2.92)
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 six months ended June 30, 2009 and 2008 (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Basic and diluted earnings per unit:				
Weighted average limited partner common units outstanding	49,039	44,510	47,189	39,745
Diluted earnings per unit:				
Weighted average limited partner units outstanding	49,039	44,510	47,189	39,745
Dilutive effect of restricted units issued	¾	153	¾	¾
Dilutive effect of senior subordinated units	¾	3,875	¾	¾
Dilutive effect of exercise of options outstanding	¾	131	¾	¾
Diluted common units	49,039	48,669	47,189	39,745
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

All common unit equivalents were anti-dilutive in the three and six months ended June 30, 2009 and the six months ended June 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% 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 June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Income allocation for incentive distributions	$ ¾	$ 12,272	$ ¾	$ 24,098
Stock-based compensation attributable to CEI's stock options and restricted shares	(760)	(1,573)	(1,406)	(2,608)
2% general partner interest in net income (loss)	(191)	702	(485)	561
General partner share of net income (loss)	$ (951)	$ 11,401	$ (1,891)	$ 22,051

CROSSTEX ENERGY, L.P.

Notes to Condensed Consolidated Financial Statements — (Continued)

(6) Employee Incentive Plans

(a) Long-Term Incentive Plans

The Partnership accounts for share-based compensation in accordance with the provisions of Statement of Financial Accounting Standards No. 123R, "*Share-Based Compensation"* (SFAS 123R) 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 June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Cost of share-based compensation charged to general and administrative expense	$ 1,867	$ 3,255	$ 3,154	$ 5,486
Cost of share-based compensation charged to operating expense	450	481	768	880
Total amount charged to income	$ 2,317	$ 3,736	$ 3,922	$ 6,366

(b) Restricted Units

The restricted units are valued at their fair value at the date of grant which is equal to the market value of common units on such date. A summary of the restricted unit activity for the six months ended June 30, 2009 is provided below:

	Six Months Ended June 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	803,632	1.97
Vested*	(113,869)	25.74
Forfeited	(109,897)	11.82
Non-vested, end of period	1,123,933	$ 11.35
Aggregate intrinsic value, end of period (in thousands)	$ 3,495	

* Vested units include 33,753 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 June 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 three months ended June 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. These performance- based units will vest if 2009 earnings before interest, taxes, depreciation, amortization, and certain other non-cash adjustments or EBITDA is (i) $220.0 million or greater, or (ii) $195.0 million or greater after making certain adjustments for commodity prices if unadjusted EBITDA is $170.0 million or greater. As of June 30, 2009, the Partnership expects to meet the performance objectives stated in the grant. 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 six months ended June 30, 2009.

CROSSTEX ENERGY, L.P.

Notes to Condensed Consolidated Financial Statements — (Continued)

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 six months ended June 30, 2009 and 2008 are provided below (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
Crosstex Energy, L.P. Restricted Units:	**2009**	**2008**	**2009**	**2008**
Aggregate intrinsic value of units vested	$ 118	$ 1,209	$ 471	$ 5,160
Fair value of units vested	$ 571	$ 734	$ 2,931	$ 5,374

As of June 30, 2009, there was $5.6 million of unrecognized compensation cost related to non-vested restricted units. That cost is expected to be recognized over a weighted-average period of 1.9 years.

(c) Unit Options

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

	Six Months Ended June 30, 2009	
Crosstex Energy, L.P. Unit Options:	**Number of Units**	**Weighted Average Exercise Price**
Outstanding, beginning of period	1,304,194	$ 30.64
Issued in exchange	344,319	4.80
Rendered in exchange	(1,032,403)	31.34
Forfeited	(130,745)	31.34
Outstanding, end of period	485,365	$ 10.68
Options exercisable at end of period	117,398	
Weighted average contractual term (years) end of period:		
Options outstanding	8.7	
Options exercisable	5.4	
Aggregate intrinsic value end of period (in thousands):		
Options outstanding	$ ¾	
Options exercisable	$ ¾	

As of June 30, 2009, there was $1.0 million of unrecognized compensation cost related to non-vested unit options. That cost is expected to be recognized over a weighted average period of 1.1 years.

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

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

	Six Months Ended June 30, 2009	
Crosstex Energy, Inc. Restricted Shares:	**Number of Shares**	**Weighted Average Grant-Date Fair Value**
Non-vested, beginning of period	604,313	$ 27.62
Vested*	(191,671)	17.06
Forfeited	(64,941)	17.34
Non-vested, end of period	347,701	$ 29.80
Aggregate intrinsic value, end of period (in thousands)	$ 1,450	

* Vested shares include 60,706 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 June 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 six months ended June 30, 2009 and 2008 are provided below (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
Crosstex Energy, Inc. Restricted Shares:	**2009**	**2008**	**2009**	**2008**
Aggregate intrinsic value of shares vested	$ 105	$ 693	$ 723	$ 12,307
Fair value of shares vested	$ 344	$ 623	$ 3,270	$ 5,799

As of June 30, 2009, there was $4.0 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 1.9 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 six months ended June 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 June 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	5.4 years

As of June 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 0.3 years.

(7) Derivatives

The Partnership manages exposure to interest rate risk and commodity price risk through the use of derivative instruments and hedging activities. The FASB issued SFAS No. 161, *"Disclosures about Derivative Instruments and Hedging Activities,"* (SFAS 161) 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 related disclosures to provide additional information about liquidity. These disclosure requirements are in addition to those already required under SFAS No. 133, *"Accounting for Derivative Instruments and Hedging Activities."* The Partnership has historically presented detailed information about derivative activities, but has updated the current disclosure to provide the requirements of SFAS 161.

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
January 22, 2008	1 year	January 31, 2008	January 31, 2009	2.8300%	100,000
					$ 550,000

* 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 SFAS No. 133 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 June 30, 2009 and 2008, and during the six months ended June 30, 2009 and 2008 is $3.4 million and $3.0 million, respectively.

The Partnership has elected not to designate any of the amended swaps or the new swap entered into in January 2008 as cash flow hedges for SFAS No. 133 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 (all swaps except the January 22, 2008 swap that expired January 31, 2009) 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 SwapTrade 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 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 June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Change in fair value of derivatives that do not qualify for hedge accounting	$ 3,036	$ 13,977	$ 3,418	$ 6,063
Realized losses on derivatives	(4,660)	(1,780)	(9,216)	(1,964)
	$ (1,624)	$ 12,197	$ (5,798)	$ 4,099

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

	June 30, 2009	December 31, 2008
Fair value of derivative assets — current	$ ¾	$ 149
Fair value of derivative liabilities — current	(17,525)	(17,217)
Fair value of derivative liabilities — long-term	(11,214)	(18,391)
Net fair value of derivatives	$ (28,739)	$ (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 liquids 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 our 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 our processing plants relating to the option to process or to bypass our equity gas. Liquids swaps are used to hedge price risk on our percent of liquids (POL) contracts.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Change in fair value of derivatives that do not qualify for hedge accounting	$ (61)	$ (1,665)	$ 464	$ (812)
Realized gains on derivatives	(398)	(1,774)	(6,340)	(3,713)
Ineffective portion of derivatives qualifying for hedge accounting	3	81	(3)	135
Net gains related to commodity swaps	(456)	(3,358)	(5,879)	(4,390)
Net (gains) losses included in income from discontinued operations	(259)	2,514	828	2,560
Gain on derivatives	$ (715)	$ (844)	$ (5,051)	$ (1,830)

CROSSTEX ENERGY, L.P.

Notes to Condensed Consolidated Financial Statements — (Continued)

The fair value of derivative assets and liabilities relating to commodity swaps excluding net fair value of derivatives included in assets held for sale of $0.6 million are as follows (in thousands):

	June 30, 2009	December 31, 2008
Fair value of derivative assets — current, designated	$ 3,778	$ 13,714
Fair value of derivative assets — current, non-designated	4,418	13,303
Fair value of derivative assets — long term, non-designated	7,553	4,628
Fair value of derivative liabilities — current, designated	(535)	¾
Fair value of derivative liabilities — current, non-designated	(3,636)	(11,289)
Fair value of derivative liabilities — long term, designated	(29)	¾
Fair value of derivative liabilities — long term, non-designated	(7,129)	(4,384)
Net fair value of derivatives	$ 4,420	$ 15,972

Set forth below is the summarized notional volumes and fair value of all instruments held for price risk management purposes and related physical offsets at June 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. Gains of $0.5 million have been reclassified from accumulated other comprehensive income into earnings as a result of the discontinuance of cash flow hedges related to assets held for sale.

June 30, 2009		
Transaction Type	**Volume**	**Fair Value**
	(In thousands)	
Cash Flow Hedges:		
Natural gas swaps (short contracts) (MMBtu's)	(300)	$ 1,060
Liquids swaps (short contracts) (gallons)	(5,766)	2,643
Less: Cash flow hedges included in assets held for sale		(489)
Total swaps designated as cash flow hedges		$ 3,214
*Mark to Market Derivatives:**		
Swing swaps (long contracts)	1,124	$ 35
Physical offsets to swing swap transactions (short contracts)	(1,124)	¾
Swing swaps (short contracts)	(1,467)	(14)
Physical offsets to swing swap transactions (long contracts)	1,467	2
Basis swaps (long contracts)	86,842	6,091
Physical offsets to basis swap transactions (short contracts)	(6,212)	23,428
Basis swaps (short contracts)	(66,772)	(4,781)
Physical offsets to basis swap transactions (long contracts)	7,136	(23,130)
Third-party on-system financial swaps (long contracts)	709	(2,251)
Physical offsets to third-party on-system transactions (short contracts)	(709)	2,319
Processing margin hedges — liquids (short contracts)	(3,425)	(207)
Processing margin hedges — gas (long contracts)	404	(95)
Liquids swaps — non-designated (short contracts)	(1,386)	(82)
Storage swap transactions (short contracts)	(212)	(11)
Less: Mark to market derivatives included in assets held for sale		(98)
Total Mark to market derivatives		$ 1,206

* All are gas contracts, volume in MMBtu's, except for processing margin hedges — liquids and liquids swaps — non-designated (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 $42.7 million would be reduced by $25.5 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 $3.5 million with financial institutions and $13.7 million with other energy companies, which represents the current gross fair value at June 30, 2009.

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 June 30,		Six Months Ended June 30,	
Increase (Decrease) in Midstream Revenue	**2009**	**2008**	**2009**	**2008**
Natural gas	$ 668	$ (1,120)	$ 1,157	$ 120
Liquids	2,588	(5,698)	7,766	(10,935)
Less: Realized gain/(losses) included in income from discontinued operations	(309)	1,610	(665)	2,133
	$ 2,947	$ (5,208)	$ 8,258	$ (8,682)

Natural Gas

As of June 30, 2009, an unrealized derivative fair value gain of $0.7 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 July 2009 gas production increased gas revenue by approximately $0.1 million.

Liquids

As of June 30, 2009, an unrealized derivative fair value gain of $2.6 million related to cash flow hedges of liquids price risk was recorded in accumulated other comprehensive income (loss). Of this net amount, a $2.5 million gain is expected to be reclassified into earnings through June 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.

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
June 30, 2009	$ 782	$ 393	$ 31	$ 1,206

(8) Fair Value Measurements

SFAS No. 157, *"Fair Value Measurements"* (SFAS 157) sets forth a framework for measuring fair value and required disclosures about fair value measurements of assets and liabilities. Fair value under SFAS 157 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.

SFAS 157 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 SFAS 157.

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

	Level 2
Interest Rate Swaps*	$ (28,739)
Commodity Swaps*	5,007
Less: Net asset value of commodity swaps included in assets held for sale	(587)
Total	$ (24,319)

* 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 loss also includes the unrealized losses on interest rate swaps of $17.0 million recorded prior to de-designation in January 2008, of which $9.8 million has been amortized to earnings through June 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).

	June 30, 2009		December 31, 2008	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Cash and cash equivalents	$ 869	$ 869	$ 1,636	$ 1,636
Trade accounts receivable and accrued revenues	205,146	205,146	341,853	341,853
Fair value of derivative assets	15,749	15,749	31,794	31,794
Note receivable	152	152	375	375
Accounts payable, drafts payable and accrued gas purchases	143,537	143,537	315,622	315,622
Current portion of long-term debt	24,412	24,412	9,412	9,412
Long-term debt	1,318,637	1,311,854	1,254,294	1,148,939
Obligations under capital lease	24,608	23,430	24,708	24,081
Fair value of derivative liabilities	40,068	40,068	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 $866.8 million and $784.0 million as of June 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 June 30, 2009, the Partnership also had borrowings totaling $476.3 million under senior secured notes with a weighted average interest rate of 10.5%. The fair value of these borrowings as of June 30, 2009 and December 30, 2008 were adjusted to reflect to current market interest rate for such borrowings as of June 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 SFAS 157.

(10) Other Income

The Partnership recorded $7.6 million in other income during the six months ended June 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.

On November 15, 2007, Crosstex CCNG Processing Ltd. ("Crosstex Processing"), the Partnership's wholly-owned subsidiary received a demand letter from Denbury Onshore, LLC ("Denbury"), asserting a claim for breach of contract and seeking payment of approximately $11.4 million in damages. On April 15, 2008, the parties mediated the matter unsuccessfully. On December 4, 2008, Denbury initiated formal arbitration proceedings against Crosstex Processing, Crosstex Energy Services, L.P., Crosstex North Texas Gathering, L.P., and Crosstex Gulf Coast Marketing, Ltd., seeking $11.4 million and additional unspecified damages. Denbury has recently amended its filings alleging fraud and seeking punitive damages. On December 23, 2008, Crosstex Processing filed an answer denying Denbury's allegations and a counterclaim seeking a declaratory judgment that its processing plant is uneconomic under the Processing Contract. Crosstex Energy, Crosstex Marketing, and Crosstex Gathering also filed an answer denying Denbury's allegations and asserting that they are improper parties as Denbury's claim is for breach of the Processing Contract and none of these entities is a party to that agreement. Crosstex Gathering also filed a counterclaim seeking approximately $40.0 million in damages for the value of the NGLs it is entitled to under its Gas Gathering Agreement with Denbury. A three-person arbitration panel has been named and discovery is in progress. Arbitration is scheduled for late 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 a number of 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 $2.2 million for July 2008 sales. The Partnership believes the July sales of $2.2 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 $2.2 million, but the allowance of the administrative claim status is still subject to approval of the bankruptcy court. The Partnership evaluated these receivables for collectability and provided a valuation allowance of $3.1 million during the year ended December 31, 2008 and $0.8 million during the three months ended June 30, 2009.

(12) Segment Information

Identification of operating segments is based principally upon differences in the types and distribution channel of products. The Partnership's reportable segments consist of Midstream and Treating. The Midstream division consists of the Partnership's natural gas gathering and transmission operations and includes the south Louisiana processing and liquids assets, the gathering and transmission assets located in north Texas, the LIG pipelines and processing plants located in Louisiana and various other small systems. Also included in the Midstream division are the Partnership's energy trading operations. The operations in the Midstream segment are similar in the nature of the products and services, the nature of the production processes, the type of customer, the methods used for distribution of products and services and the nature of the regulatory environment. The Treating division generates fees from its plants either through volume-based treating contracts or through fixed monthly payments. Segment data does not include assets held for sale.

The Partnership evaluates the performance of its operating segments based on operating revenues and segment profits. Corporate expenses include general partnership expenses associated with managing all reportable operating segments. Corporate assets consist principally of property and equipment, including software, for general corporate support, working capital and debt financing costs.

CROSSTEX ENERGY, L.P.

Notes to Condensed Consolidated Financial Statements — (Continued)

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

	Midstream	Treating	Corporate	Totals
		(In thousands)		
Three months ended June 30, 2009:				
Sales to external customers	$ 347,820	$ 13,892	$ ¾	$ 361,712
Sales to affiliates	¾	1,559	(1,559)	¾
Profit on energy trading activities	1,427	¾	¾	1,427
Purchased gas	(270,845)	¾	¾	(270,845)
Operating expenses	(28,482)	(5,738)	1,559	(32,661)
Segment profit	$ 49,920	$ 9,713	$ ¾	$ 59,633
Gain on derivatives	$ 715	$ ¾	$ ¾	$ 715
Depreciation and amortization	$ (29,416)	$ (3,010)	$ (1,322)	$ (33,748)
Capital expenditures	$ 24,152	$ 582	$ 405	$ 25,139
Identifiable assets	$ 2,022,061	$ 198,086	$ 34,365	$ 2,254,512
Three months ended June 30, 2008:				
Sales to external customers	$ 996,000	$ 11,647	$ ¾	$ 1,007,647
Sales to affiliates	¾	1,223	(1,223)	¾
Profit on energy trading activities	828	¾	¾	828
Purchased gas	(916,776)	¾	¾	(916,776)
Operating expenses	(29,086)	(5,877)	1,223	(33,740)
Segment profit	$ 50,966	$ 6,993	$ ¾	$ 57,959
Gain on derivatives	$ 844	$ ¾	$ ¾	$ 844
Depreciation and amortization	$ (24,445)	$ (2,893)	$ (1,780)	$ (29,118)
Capital expenditures	$ 52,993	$ 12,740	$ 2,864	$ 68,597
Identifiable assets	$ 2,555,412	$ 223,985	$ 54,663	$ 2,834,060
Six months ended June 30, 2009:				
Sales to external customers	$ 700,257	$ 28,204	$ ¾	$ 728,461
Sales to affiliates	¾	3,143	(3,143)	¾
Profit on energy trading activities	2,141	¾	¾	2,141
Purchased gas	(555,351)	¾	¾	(555,351)
Operating expenses	(57,023)	(10,709)	3,143	(64,589)
Segment profit	$ 90,024	$ 20,638	$ ¾	$ 110,662
Gain on derivatives	$ 5,051	$ ¾	$ ¾	$ 5,051
Depreciation and amortization	$ (56,520)	$ (6,003)	$ (2,790)	$ (65,313)
Capital expenditures	$ 58,463	$ 5,489	$ 1,122	$ 65,074
Identifiable assets	$ 2,022,061	$ 198,086	$ 34,365	$ 2,254,512
Six months ended June 30, 2008:				
Sales to external customers	$ 1,794,902	$ 22,727	$ ¾	$ 1,817,629
Sales to affiliates	¾	2,338	(2,338)	¾
Profit on energy trading activities	1,684	¾	¾	1,684
Purchased gas	(1,634,360)	¾	¾	(1,634,360)
Operating expenses	(59,557)	(12,863)	2,338	(70,082)
Segment profit	$ 102,669	$ 12,202	$ ¾	$ 114,871
Gain on derivatives	$ 1,830	$ ¾	$ ¾	$ 1,830
Depreciation and amortization	$ (48,674)	$ (5,829)	$ (3,497)	$ (58,000)
Capital expenditures	$ 115,583	$ 17,208	$ 4,398	$ 137,189
Identifiable assets	$ 2,555,412	$ 223,985	$ 54,663	$ 2,834,060

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Segment profits	$ 59,633	$ 57,959	$ 110,662	$ 114,871
General and administrative expenses	(14,129)	(17,313)	(28,342)	(32,768)
Gain on derivatives	715	844	5,051	1,830
Gain (loss) on sale of property	(284)	1,381	594	1,641
Depreciation and amortization	(33,748)	(29,118)	(65,313)	(58,000)
Operating income	$ 12,187	$ 13,753	$ 22,652	$ 27,574

(13) Subsequent Events

The Partnership evaluated events subsequent to the quarter ending June 30, 2009 through the date of the issuance of the financial statements on August 7, 2009. The only event of impact to the financial presentation of the Partnership relates to the closing of the sale of assets disclosed in Note 2 to the financial statements.

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. We have two industry segments, Midstream and Treating, with a geographic focus in the north Texas Barnett Shale area and in Louisiana. Our Midstream division focuses on the gathering, processing, transmission and marketing of natural gas and natural gas liquids (NGLs), as well as providing certain producer services, while our Treating division focuses on the removal of contaminants from natural gas and NGLs to meet pipeline quality specifications. For the six months ended June 30, 2009, 83.9% of our gross margin was generated in the Midstream division with the balance in the Treating division. 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, market or treat 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 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 liquids produced to protect our margins from changes in liquids prices.

Our Midstream segment 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. Our Treating segment margins are largely a function of the number and size of treating plants in operation as well as fees earned for removing impurities at a non-operated processing plant. We generate Midstream revenues from five primary sources:

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

With respect to our Midstream services, we generally gather or transport gas owned by others through our facilities for a fee, or we buy natural gas from a producer, plant or shipper at either a fixed discount to a market index or a percentage of the market index, then transport and resell the natural gas. In our purchase/sale transactions, the resale price is generally based on the same index price at which the gas was purchased, and, if we are to be profitable, at a smaller discount or larger premium to the index than it 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 in our Midstream segment from our processing services primarily 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.

We generate treating revenues under three arrangements:

- a volumetric fee based on the amount of gas treated, which accounted for 6.4% and 10.9% of the operating income in our Treating division for the six months ended June 30, 2009 and 2008, respectively;
- a fixed fee for operating the plant for a certain period, which accounted for 66.7% and 60.2% of the operating income in our Treating division for the six months ended June 30, 2009 and 2008, respectively; or
- a fee arrangement in which the producer operates the plant, which accounted for 26.9% and 28.9% of the operating income in our Treating division for the six months ended June 30, 2009 and 2008, respectively.

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 volume of gas moved through the asset.

Recent Developments

Global financial markets and economic conditions have been, and continue to be, disrupted and volatile. Numerous events have severely restricted current liquidity in the capital markets throughout the United States and around the world. The ability to raise money in the debt and equity markets has diminished significantly and, if available, the cost of funds has increased substantially. One of the features driving investments in MLPs , including the Partnership, over the past few years has been the distribution growth offered by MLPs due to liquidity in the financial markets for capital investments to grow distributable cash flow through development projects and acquisitions. Growth opportunities have been and are expected to continue to be constrained by the lack of liquidity in the financial markets.

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

- Prices of oil, natural gas and NGLs remain below the market price realized throughout most of 2008.
- As a result of lower NGL prices and the related fractionation spreads and POL fees, our processing margins in 2009 have been substantially lower than the processing margins realized in 2008. For the six months ended June 30, 2009, approximately 26.7% of our gross margin was attributable to gas processing as compared to 36.9% of our gross margin for the six months ended June 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. Most of the production from the pipeline systems supplying the Eunice and Sabine plants has been restored to pre-hurricane levels as of June 30, 2009 but our processing volumes at the plants during the first half of 2009 were negatively impacted by lower pipeline system supplies. Processing volumes at the Pelican processing plant during the first half of 2009 were also negatively impacted by lower pipeline system supplies and one of the pipeline systems is not expected to be in service until mid-August when repairs are expected to be completed.

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 $10.6 million and the August 2009 sale of our south Texas, Mississippi and Alabama properties for approximately $220.0 million, and we may consider marketing certain other non-strategic assets for sale during the last half of 2009.
- 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 will increase and our ability to pay distributions and incur additional indebtedness are restricted when we are operating at higher leverage ratios.

Results of Operations

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(Dollars in millions)			
Midstream revenues	$ 347.8	$ 996.0	$ 700.3	$ 1,794.9
Midstream purchased gas	(270.8)	(916.7)	(555.4)	(1,634.3)
Profit on energy trading activities	1.4	0.8	2.1	1.7
Midstream gross margin	78.4	80.1	147.0	162.3
Treating gross margin	13.9	11.6	28.2	22.7
Total gross margin	$ 92.3	$ 91.7	$ 175.2	$ 185.0
Midstream Volumes (MMBtu/d):				
Gathering and transportation	2,123,000	2,027,000	2,082,000	2,015,000
Processing	1,189,000	1,915,000	1,148,000	1,959,000
Producer services	61,000	90,000	85,000	85,000
Plants in service at end of period	180	180	180	180

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

Gross Margin and Profit on Energy Trading Activities. Midstream gross margin was $78.4 million for the three months ended June 30, 2009 compared to $80.1 million for the three months ended June 30, 2008, a decrease of $1.7 million, or 2.1%. The decrease was realized primarily at our processing facilities which were negatively impacted by lower NGL prices than in the second quarter 2008, combined with a decline in inlet volumes. This decrease was partially offset by gross margin gains on our gathering and transmission systems due to expansion projects and increased throughput. Profit on energy trading activities increased for the comparative periods by approximately $0.6 million.

The weaker processing environment contributed to a significant decline in the gross margin for our processing plants in Louisiana for the quarter ended June 30, 2009. The Riverside facility reported a margin decline of $4.7 million primarily due to a decrease in processed volumes. The Plaquemine, Gibson and Sabine Pass plants all experienced an inlet volume decrease and reported gross margin declines of $2.6 million, $2.1 million and $1.8 million, respectively. The Blue Water plant, which has been shut down for several months due to a change in pipeline operations, realized a gross margin decline of $1.5 million. A decrease in throughput volume on the east Texas system led to a gross margin decline of $1.3 million. 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. Increased throughput on the north Texas gathering and transmission systems contributed $6.8 million of gross margin growth for the quarter ended June 30, 2009. The Eunice plant had a margin increase of $3.5 million for the three months ended June 30, 2009 primarily due to improved contract terms and operational efficiencies. The LIG gathering and transmission system contributed margin growth of $2.6 million for the comparative periods due to the north Louisiana expansion.

Treating gross margin was $13.9 million for the three months ended June 30, 2009 compared to $11.6 million for the three months ended June 30, 2008, an increase of $2.2 million, or 19.3%. Treating plants, dew point control plants, and related equipment in service totaled 180 plants at both June 30, 2009 and June 30, 2008. Timing, size and increased monthly fees on plants placed in service versus plants coming out of service and increased fees on existing month to month treating contracts make up $2.0 million of the increase. Field services provided to producers also contributed gross margin growth of $0.3 million for the comparable periods.

Operating Expenses. Operating expenses were $32.7 million for the three months ended June 30, 2009 compared to $33.7 million for the three months ended June 30, 2008, a decrease of $1.1 million, or 3.2%. 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 $14.1 million for the three months ended June 30, 2009 compared to $17.3 million for the three months ended June 30, 2008, a decrease of $3.2 million, or 18.4%. The decrease is a result of strategic initiatives undertaken to reduce expenses and primarily relate to workforce reductions.

Gain on Sale of Property. The $1.4 million gain on property sold during the three months ended June 30, 2008 consisted of various small Treating and Midstream assets.

Gain/Loss on Derivatives. We had a gain on commodity derivatives of $0.7 million for the three months ended June 30, 2009 compared to a gain of $0.8 million for the three months ended June 30, 2008. The derivative transaction types contributing to the net gain are as follows (in millions):

	Three Months Ended June 30,			
	2009		2008	
(Gain)/Loss on Derivatives:	**Total**	**Realized**	**Total**	**Realized**
Basis swaps	$ (0.9)	$ (0.3)	$ (3.4)	$ (1.7)
Processing margin hedges	0.4	0.1	¾	¾
Other	0.1	(0.1)	¾	(0.1)
	(0.4)	(0.3)	(3.4)	(1.8)
Less: Derivative gains related to assets held for sale and included in income from discontinued operations	(0.3)	0.1	2.6	0.9
Gain on Derivatives	$ (0.7)	$ (0.2)	$ (0.8)	$ (0.9)

Depreciation and Amortization. Depreciation and amortization expenses were $33.7 million for the three months ended June 30, 2009 compared to $29.1 million for the three months ended June 30, 2008, an increase of $4.6 million, or 15.9%. Midstream depreciation and amortization increased $4.9 million primarily due to the north Texas expansion and depreciation acceleration resulting from the abandonment of certain planned projects.

Interest Expense. Interest expense was $26.1 million for the three months ended June 30, 2009 compared to $2.0 million for the three months ended June 30, 2008, an increase of $24.1 million. Interest expense increased $8.5 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 increase primarily relates to interest rate derivatives which yielded a decline in mark to market income as well as an increase in realized expense due to the decrease in LIBOR rates. Net interest expense consists of the following (in millions):

	Three Months Ended June 30,	
	2009	**2008**
Credit facility	$ 11.6	$ 6.6
Senior notes	9.0	7.1
PIK notes	1.6	¾
Capitalized interest	(0.5)	(0.6)
Mark to market interest rate swaps	(3.0)	(14.0)
Realized interest rate swap losses	4.7	1.8
Interest income	¾	(0.1)
Other	2.7	1.2
Total	$ 26.1	$ 2.0

Income Taxes. Income tax expense was $0.6 million for the three months ended June 30, 2009 compared to $0.3 million for the three months ended June 30, 2008, an increase of $0.3 million. The increase relates primarily to the Texas margin tax.

Discontinued Operations. As part of our strategy to increase liquidity in response to the worsening conditions in the financial and commodity markets, we have sold and have agreed to sell certain non-strategic assets. We sold our undivided 12.4% interest in the Seminole gas processing plant to a third party in November 2008. In addition, we entered into an agreement to sell our assets in Mississippi, Alabama and south Texas. The sale closed on August 6, 2009. In accordance with SFAS No. 144, "*Accounting for the Impairment or Disposal of Long-Lived Assets*," the results of operations related to the Seminole gas processing plant and the assets held for sale are presented in income from discontinued operations for the comparative periods in the statements of operations. Revenues, the related costs of operations, depreciation and amortization, and allocated interest are reflected in the income from discontinued operations. No income taxes are attributed to income from discontinued operations and no 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 June 30,	
	2009	**2008**
Midstream revenues	$ 134.5	$ 528.4
Treating revenues	$ 1.6	$ 6.3
Net income from discontinued operations	$ 4.0	$ 9.9
Gathering and Transmission Volumes (MMBtu/d)	549,000	577,000
Processing Volumes (MMBtu/d)	189,000	206,000

Six Months Ended June 30, 2009 Compared to Six Months Ended June 30, 2008

Gross Margin and Profit on Energy Trading Activities. Midstream gross margin was $147.0 million for the six months ended June 30, 2009 compared to $162.3 million for the six months ended June 30, 2008, a decrease of $15.2 million, or 9.4%. The decrease was realized primarily at our processing facilities which were negatively impacted by lower NGL prices than in the first half of 2008, combined with a decline in inlet volumes. This decrease was partially offset by gross margin gains on our gathering and transmission systems due to expansion projects and increased throughput. Profit on energy trading activities increased for the comparative periods by approximately $0.4 million.

The weaker processing environment contributed to a significant decline in the gross margin for the processing plants in Louisiana for the six months ended June 30, 2009. Total gross margin for the region associated with natural gas processing activity was down $27.8 million compared to the same period in 2008. The most significant contributors to this decrease were the Plaquemine, Gibson and Riverside facilities which reported margin declines of $8.0 million, $7.4 million and $4.9 million, respectively. A decrease in throughput volume on the east Texas system led to a gross margin decline of $2.1 million. The processing facilities in the north Texas region, which were also impacted by a weaker NGL market, realized a gross margin decline of $1.7 million. The Arkoma system, which was sold in April 2009, created a negative gross margin variance of $1.3 million when compared to the same period in 2008. Increased throughput on the north Texas gathering and transmission systems contributed $17.1 million of gross margin growth for the six months ended June 30, 2009. The LIG gathering and transmission system contributed margin growth of $0.8 million for the comparative periods due to north Louisiana expansions.

Treating gross margin was $28.2 million for the six months ended June 30, 2009 compared to $22.7 million for the same period in 2008, an increase of $5.5 million, or 24.1%. Treating plants, dew point control plants, and related equipment in service totaled 180 plants at both June 30, 2009 and June 30, 2008. Timing, size and increased monthly fees on plants placed in service versus plants coming out of service and increased fees on existing month to month treating contracts make up $5.1 million of the increase. Field services provided to producers also contributed gross margin growth of $0.4 million for the comparative periods.

Operating Expenses. Operating expenses were $64.6 million for the six months ended June 30, 2009 compared to $70.1 million for the six months ended June 30, 2008, a decrease of $5.5 million, or 7.8%. 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 $28.3 million for the six months ended June 30, 2009 compared to $32.8 million for the six months ended June 30, 2008, a decrease of $4.4 million, or 13.5%. The decrease is primarily attributable to the following factors:

- $2.3 million decrease in stock-based compensation expense resulting from the reduction of estimated performance-based restricted units and restricted shares and a workforce reduction in January 2009;
- $1.8 million decrease in labor and benefits related to a workforce reduction in January 2009;
- $1.6 million decrease in various expenses, including professional fees and services, office supplies and expenses, travel and training resulting from initiatives undertaken in late 2008 and early 2009 to reduce expenses;
- $0.9 million increase in bad debt expense; and
- $0.4 million increase in exit and disposal expense resulting primarily from the additional costs associated with the cancelled relocation of our corporate headquarters.

Gain on Sale of Property. The $1.6 million gain on sale of property for the six months ended June 30, 2008 represents disposition of various small Treating and Midstream assets.

Gain/Loss on Derivatives. We had a gain on commodity derivatives of $5.1 million for the six months ended June 30, 2009 compared to a gain of $1.8 million for the six months ended June 30, 2008. The derivative transaction types contributing to the net gain are as follows (in millions):

	Six Months Ended June 30,			
	2009		2008	
(Gain)/Loss on Derivatives:	**Total**	**Realized**	**Total**	**Realized**
Basis swaps	$ (1.8)	$ (1.0)	$ (4.7)	$ (3.6)
Processing margin hedges	(3.7)	(4.0)	0.2	0.2
Other	(0.4)	(1.3)	0.1	(0.1)
	(5.9)	(6.3)	(4.4)	(3.5)
Less: Derivative gains related to assets held for sale and included in income from discontinued operations	0.8	0.5	2.6	1.2
Gain on Derivatives	$ (5.1)	$ (5.8)	$ (1.8)	$ (2.3)

Depreciation and Amortization. Depreciation and amortization expenses were $65.3 million for the six months ended June 30, 2009 compared to $58.0 million for the six months ended June 30, 2008, an increase of $7.3 million, or 12.6%. Midstream depreciation and amortization expense increased $7.8 million primarily due to the north Texas expansion and depreciation acceleration resulting from the abandonment of certain planned projects.

Interest Expense. Interest expense was $48.4 million for the six months ended June 30, 2009 compared to $26.6 million for the six months ended June 30, 2008, an increase of $21.8 million. Interest expense increased $8.1 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 increase primarily relates to interest rate derivatives which yielded a decline in mark to market income as well as an increase in realized expense due to the decrease in LIBOR rates. Net interest expense consists of the following (in millions):

	Six Months Ended June 30,	
	2009	**2008**
Credit facility	$ 19.0	$ 16.5
Senior notes	17.6	14.1
PIK notes	2.1	¾
Capitalized interest	(1.0)	(1.7)
Mark to market interest rate swaps	(3.4)	(6.1)
Realized interest rate swap losses	9.2	1.8
Interest income	¾	(0.2)
Other	4.9	2.2
Total	$ 48.4	$ 26.6

Income Taxes. Income tax expense was $1.2 million for the six months ended June 30, 2009 compared to $0.7 million for the six months ended June 30, 2008, an increase of $0.5 million. The increase relates primarily to the Texas margin tax.

Loss on Extinguishment of Debt. We recognized a loss on extinguishment of debt during the six months ended June 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 EITF Issue No. 96-19, "*Debtor's Accounting for a Modification or Exchange of Debt Instruments*" 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 in the first half of 2009.

Other Income. We recorded $7.6 million in other income during the six months ended June 30, 2008, primarily from the settlement of disputed liabilities that were assumed with an acquisition.

Discontinued Operations. As part of our strategy to increase liquidity in response to the tightening financial markets, we have sold and have agreed to sell certain non-strategic assets. We sold our undivided 12.4% interest in the Seminole gas processing plant to a third party in November 2008. In addition, we entered into an agreement to sell our assets in Mississippi, Alabama and south Texas. The sale closed on August 6, 2009. In accordance with SFAS No. 144, "*Accounting for the Impairment or Disposal of Long-Lived Assets*," the results of operations related to the Seminole gas processing plant and the assets held for sale are presented in income from discontinued operations for the comparative periods in the statements of operations. Revenues, the related costs of operations, depreciation and amortization, and allocated interest are reflected in the income from discontinued operations. No income taxes are attributed to income from discontinued operations and no 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):

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Midstream revenues	$ 313.7	$ 981.7
Treating revenues	$ 3.5	$ 11.6
Net income from discontinued operations	$ 5.8	$ 17.7
Gathering and Transmission Volumes (MMBtu/d)	564,000	557,000
Processing Volumes (MMBtu/d)	191,000	210,000

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

Cash Flows from Operating Activities. Net cash provided by operating activities was $19.0 million for the six months ended June 30, 2009 compared to $86.6 million for the six months ended June 30, 2008. Income before non-cash income and expenses and changes in working capital for comparative periods were as follows (in millions):

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Income before non-cash income and expenses	$ 53.1	$ 90.8
Changes in working capital	$ (34.1)	$ (4.2)

The primary reason for the decrease in income before non-cash income and expenses of $37.7 million from 2008 to 2009 was decreased net income. Our 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 six months ended June 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.

Cash Flows from Investing Activities. Net cash used in investing activities was $56.1 million and $147.5 million for the six months ended June 30, 2009 and 2008, respectively. Our primary investing activities were capital expenditures for internal growth, net of accrued amounts, as follows (in millions):

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Growth capital expenditures	$ 70.1	$ 143.7
Maintenance capital expenditures	4.8	7.6
Total	$ 74.9	$ 151.3

Net cash invested in Midstream assets was $64.6 million and $124.9 million for the six months ended June 30, 2009 and 2008, respectively. Net cash invested in Treating assets was $9.2 million for the six months ended June 30, 2009 and $23.0 million for the six months ended June 30, 2008. Net cash invested in other corporate assets was $1.1 million for the six months ended June 30, 2009 and $3.4 million for the six months ended June 30, 2008.

Cash flows from investing activities for the six months ended June 30, 2009 and 2008 also include proceeds from property sales of $10.7 million and $3.8 million, respectively. The Arkoma asset was sold in the first half of 2009 for net proceeds of $10.6 million. The 2008 sales primarily related to sales of various small Midstream and Treating assets.

Cash Flows from Financing Activities. Net cash provided by financing activities was $36.3 million and $67.8 million for the six months ended June 30, 2009 and 2008, respectively. Our financing activities primarily relate to funding of capital expenditures. Our financings have primarily consisted of borrowings under our bank credit facility, borrowings under capital lease obligations, equity offerings and senior note repayments during 2009 and 2008 as follows (in millions):

	Six Months Ended June 30,	
	2009	**2008**
Net borrowings under bank credit facility	$ 82.8	$ 36.0
Senior note repayments	(4.7)	(4.7)
Net borrowings under capital lease obligations	0.1	11.9
Debt refinancing costs	(13.4)	(0.2)
Common unit offerings (1)	¾	102.0

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

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

	Six Months Ended June 30,	
	2009	**2008**
Common units	$ 11.4	$ 42.9
Subordinated units	¾	2.8
General partner	0.2	20.5
Total	$ 11.6	$ 66.2

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 $1.181 billion credit facility to fund checks as they are presented. As of June 30, 2009, we had approximately $199.8 million of available borrowing capacity under this facility. Changes in drafts payable for the six months ended 2009 and 2008 were as follows (in millions):

	Six Months Ended June 30,	
	2009	**2008**
Decrease in drafts payable	$ 16.5	$ 10.5

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

Capital Requirements. We have reduced our budgeted capital expenditures significantly for 2009 due to limited access to funding. The current economic climate and our leveraged position have limited our ability to secure additional funding for growth and expansion projects. Total growth 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 first half of 2009, our growth capital expenditures were $70.1 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 Red River lateral 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 also continued our expansion of our north Texas pipeline gathering system in the Barnett Shale on a limited basis during the first half of 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 61 new wells during the first half of 2009.

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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 June 30, 2009, is as follows (in millions):

	Payments Due by Period						
	Total	**2009**	**2010**	**2011**	**2012**	**2013**	**Thereafter**
Long-term debt	$ 1,343.0	$ 4.7	$ 20.3	$ 900.0	$ 93.0	$ 93.0	$ 232.0
Interest payable on fixed long-term debt obligations	202.1	21.9	42.5	40.8	36.0	27.4	33.5
PIK interest payable	18.6	¾	¾	18.6	¾	¾	¾
Capital lease obligations	32.9	1.6	3.4	3.4	3.4	3.4	17.7
Operating leases	76.4	15.2	19.7	18.1	16.6	3.1	3.7
Unconditional purchase obligations	1.5	1.5	¾	¾	¾	¾	¾
FIN 48 tax obligations	2.3	2.0	0.1	0.1	0.1	¾	¾
Total contractual obligations	$ 1,676.8	$ 46.9	$ 86.0	$ 981.0	$ 149.1	$ 126.9	$ 286.9

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

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 June 30, 2009, annual interest payments would be $58.5 million. The interest amounts also exclude estimates of the effect of our interest rate swap contracts.

In the fourth quarter of 2009, we will be required to post a $32.7 million letter of credit for the Eunice lease obligation. The annual obligations under the Eunice lease of $6.1 million for 2009 and $12.2 million per year for 2010 thru 2012 are reflected in the table above as operating lease obligations.

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

Indebtedness

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

	June 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 June 30, 2009 and December 31, 2008 were 6.75% and 3.9%, respectively	$ 866.7	$ 784.0
Senior secured notes (including PIK notes of $1.3 million), weighted average interest rates at June 30, 2009 and December 31, 2008 were 10.5% and 8.0%, respectively	476.3	479.7
	1,343.0	1,263.7
Less current portion	(24.4)	(9.4)
Debt classified as long-term	$ 1,318.6	$ 1,254.3

As of June 30, 2009, we had a bank credit facility with a borrowing capacity of $1.181 billion that matures in June 2011. As of June 30, 2009, $981.2 million was outstanding under the bank credit facility, including $114.4 million of letters of credit, leaving approximately $199.8 million available for future borrowing. The bank credit facility is guaranteed by certain of our subsidiaries. On August 6, 2009, we sold our Mississippi, Alabama and south Texas assets, which were reflected as assets held for sale as of June 30, 2009, for proceeds of $220.0 million. Sales proceeds, net of transaction costs and other obligations associated with the sale, of $212.0 million were used to repay long-term debt and permanently reduce commitments under our bank credit facility. Our bank credit facility requires us to pay a leverage fee if we do 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. If we fail to meet any de-leveraging target, we must pay a leverage fee equal to the product of the aggregate commitments outstanding under our bank credit facility and the outstanding amounts of the senior secured note agreement on such date, and 1.0% on September 30, 2009, 1.0% on December 31, 2009 and 2.0% on March 31, 2010. This leverage fee will accrue on the applicable date, but not be payable until we refinance our bank credit facility. The August 2009 repayment made with the proceeds from the disposition of Mississippi, Alabama and south Texas assets satisfied the September 30, 2009 and December 31, 2009 de-leveraging targets. As of August 6, 2009, after giving effect to this sale of assets, the repayment of long-term debt and the reduction of commitments under our bank credit facility as a result of such sale, we had a bank credit facility with a borrowing capacity of $1.038 billion and $405.4 million (including PIK) of outstanding senior secured notes.

Recent Accounting Pronouncements

In December 2007, the FASB issued SFAS No. 141R, *"Business Combinations"* (SFAS 141R) and SFAS No. 160, *"Noncontrolling Interests in Consolidated Financial Statements"* (SFAS 160). SFAS 141R requires most identifiable assets, liabilities, noncontrolling 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 SFAS 141R, all business combinations will be accounted for by applying the acquisition method. SFAS 141R is effective for periods beginning on or after December 15, 2008. SFAS 160 requires noncontrolling 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. SFAS 160 was adopted January 1, 2009 and comparative period information has been recast to classify noncontrolling interests in equity and attribute net income and other comprehensive income to noncontrolling interests.

In March of 2008, the FASB issued Statement of Financial Accounting Standards No. 161,*"Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133"* (SFAS 161). SFAS 161 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 SFAS 133, and how the instruments and related hedged items affect the financial position, results of operations and cash flows of the entity. SFAS 161 is effective for fiscal years beginning after November 15, 2008. SFAS 161 was adopted effective January 1, 2009 and we added the required disclosures.

In May 2008, the FASB issued SFAS No. 162, "*The Hierarchy of Generally Accepted Accounting Principles"* (SFAS 162) with an effective date of January 1, 2009. SFAS 162 was intended to improve financial reporting by identifying a consistent framework, or hierarchy, for selecting accounting principles to be used in preparing financial statements of nongovernmental entities that are presented in conformity with generally accepted accounting principles 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 will become the exclusive authoritative reference for nongovernmental 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 nongovernmental U.S. GAAP into the authoritative Codification and guidance that is nonauthoritative. The contents of the Codification will carry the same level of authority, eliminating the four-level GAAP hierarchy previously set forth in Statement 162. The Codification will supersede all existing non-SEC accounting and reporting standards. All other non-grandfathered, non-SEC accounting literature not included in the Codification will become nonauthoritative. We will be revising all GAAP references to reflect the Codification for the quarter ending September 30, 2009.

In June 2008, the Financial Accounting Standards Board (FASB) issued Staff Position FSP EITF 03-6-1 (the FSP) which requires unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents to be treated as *participating securities* as defined in EITF Issue No. 03-6, "Participating Securities and the Two-Class Method under FASB Statement No. 128," and, therefore, included in the earnings allocation in computing earnings per share under the two-class method described in FASB Statement No. 128, *Earnings per Share.* The FSP is effective for financial statements issued for fiscal years beginning after December 15, 2008 and interim periods within those years. We adopted the FSP effective January 1, 2009 and adjusted all prior reporting periods to conform to the requirements.

In addition, the FASB issued EITF 07-4, "Application of the Two-Class Method under FASB Statement No. 128, *Earnings per Share*, to Master Limited Partnerships' which addresses the consensus reached by the Task Force that incentive distribution rights (IDRs) in a typical master limited partnership are participating securities under FASB Statement No. 128, Earnings per Share, 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. Currently this EITF has no impact on us.

In June 2009, the FASB issued SFAS No. 167, "*Amendments to FASB Interpretation No. 46(R) (SFAS 167).*" SFAS 167 amends the guidance in FASB Interpretation 46R related to the consolidation of variable interest entities or VIEs. It requires reporting entities to evaluate former Qualifying Special Purpose Entities or QSPEs for consolidation, changes the approach to determining a VIE's 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 FSP FAS 140-4 and FIN 46(R)-8, "*Disclosures by Public Entities (Enterprises) about Transfers of Financial Assets and Interests in Variable Interest Entities*." 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.

In June 2009, the FASB issued FASB Statement No. 165, "*Subsequent Events,*" that 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.

The FASB recently issued Staff Position FSP FAS 107-1 and APB 28-1, "*Interim Disclosures about Fair Value of Financial Instruments*," requiring publicly traded companies, as defined in Opinion 28, to disclose the fair value of financial instruments within the scope of FASB Statement No. 107, "*Disclosures about Fair Value of Financial Instruments*," in interim financial statements, adding to the current requirement to make those disclosures in annual financial statements. The Staff Position 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 also 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 June 30, 2009, our bank credit facility had outstanding borrowings of $866.8 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 addition, we entered into one new interest rate swap in January 2008 covering $100.0 million of the variable rate debt for a period of one year at an interest rate of 2.83%. 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 June 30, 2009, the fair value of these interest rate swaps was reflected as a liability of $28.7 million ($17.5 million in net current liabilities and $11.2 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 $17.6 million. Considering the interest rate swaps and the amount outstanding on our bank credit facility as of June 30, 2009, we estimate that a 1% increase or decrease in the interest rate would change our annual interest expense by approximately $4.2 million for periods when the entire portion of the $450.0 million of interest rate swaps are outstanding and $8.7 million for annual periods after 2011 when all the interest rate swaps lapse.

At June 30, 2009, we had total fixed rate debt obligations of $476.3 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 $469.5 million as of June 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 $17.4 million based on the debt obligations as of June 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 types, gathering and transportation margins and treating margins as a percent of total gross margin for the comparative year-to-date periods are as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	**2008**	**2009**	**2008**
Gathering and transportation margin	59.7%	57.7%	57.2%	50.8%
Gas processing margins:				
Processing margin	5.7%	14.7%	5.0%	17.7%
Percent of liquids	10.4%	10.8%	12.4%	13.1%
Fee based	9.2%	4.1%	9.3%	6.1%
Total gas processing	25.3%	29.6%	26.7%	36.9%
Treating margin	15.0%	12.7%	16.1%	12.3%
Total	100.0%	100.0%	100.0%	100.0%

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

Period	Underlying	Notional Volume	We Pay	We Receive	Fair Value Asset/(Liability) (in thousands)
July 2009–December 2009	Ethane	61 (MBbls)	Index	$0.407 - $0.785/gal	$ 424
July 2009–December 2009	Propane	43 (MBbls)	Index	$0.7015 - $1.39/gal	828
July 2009–December 2009	Iso Butane	11 (MBbls)	Index	$0.97 - $1.7375/gal	227
July 2009–December 2009	Normal Butane	14 (MBbls)	Index	$0.875 - $1.705/gal	286
July 2009–December 2010	Natural Gasoline	42 (MBbls)	Index	$1.15 - $2.1275/gal	797
					$ 2,562
				Less: Fair value asset included in assets held for sale	(157)
					$ 2,405

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 46.5% of our hedgeable volumes at risk through the end of 2009 (17.7% of total volumes at risk through the end of 2009). We have also hedged 21.3% of our hedgeable natural gasoline volumes for 2010 (6.6% of total natural gasoline volumes at risk for 2010).

We also have hedges in place at June 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)
July 2009 – October 2009	Ethane	37 (MBbls)	Index	$0.407 - $0.44/gal	$ (62)
July 2009 – October 2009	Propane	18 (MBbls)	Index	$0.7015 - $0.84/gal	(25)
July 2009 – October 2009	Iso Butane	6 (MBbls)	Index	$0.97 - $1.105/gal	(26)
July 2009 – October 2009	Normal Butane	7 (MBbls)	Index	$0.875 - $1.05/gal	(30)
July 2009 – October 2009	Natural Gasoline	15 (MBbls)	Index	$1.15 - $1.385/gal	(64)
July 2009 – October 2009	Natural Gas	3,284 (MMBtu/d)	$4.06-$4.33/MMBtu	Index	(95)
					$ (302)

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 5.0% 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 35.0% 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 June 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 $4.4 million. The aggregate effect of a hypothetical 10% increase in gas and NGL prices would result in a decrease of approximately $0.9 million in the net fair value asset of these contracts as of June 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 June 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 June 30, 2009 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II—OTHER INFORMATION

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

Information about risk factors for the three months ended June 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.

Item 4. ***Submission of Matters to a Vote of Security Holders***

We held a special meeting of unitholders on May 7, 2009. At the meeting, the following proposals were approved by the margins indicated below:

1. To approve the Crosstex Energy GP, LLC Amended and Restated Long-Term Incentive Plan:

For	27,832,799
Against	930,576
Abstain	233,588
Broker Non-Vote	None

2. To approve an amendment to the Crosstex Energy GP, LLC Amended and Restated Long-Term Incentive Plan to allow for an option exchange program for employees other than directors and executive officers:

For	27,989,658
Against	799,983
Abstain	207,323
Broker Non-Vote	None

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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. In accordance with the instructions to Item 601(b)(2) of Regulation S-K, the exhibits and schedules to the foregoing Partnership Interest Purchase and Sale Agreement are not filed herewith. The Agreement identifies such exhibits and schedules, including the general nature of their content. We undertake to provide such exhibits and schedules to the Securities and Exchange Commission upon request (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).
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).
10.1	—	Crosstex Energy GP, LLC Amended and Restated Long-Term Incentive Plan, dated March 17, 2009 (incorporated by reference to Exhibit 10.3 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2009).
10.2	—	Crosstex Energy, Inc. 2009 Long-Term Incentive Plan, effective March 17, 2009 (incorporated by reference to Exhibit 10.3 to Crosstex Energy, Inc.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2009).
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.

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

August 7, 2009

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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.

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 case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

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

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

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

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

Date: August 7, 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 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: August 7, 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 June 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 result of operations of the Registrant.

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

August 7, 2009

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

August 7, 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.