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, 2008

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 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 31, 2008, the Registrant had 44,866,546 common units and 3,875,340 senior subordinated series D units outstanding.

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CROSSTEX ENERGY, L.P.

Condensed Consolidated Balance Sheets

	June 30, 2008 (Unaudited)	December 31, 2007
	(In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 7,045	$ 142
Accounts and notes receivable, net:		
Trade, accrued revenue and other	746,211	497,311
Related party	797	38
Fair value of derivative assets	20,567	8,589
Natural gas and natural gas liquids, prepaid expenses and other	34,474	16,062
Total current assets	809,094	522,142
Property and equipment, net of accumulated depreciation of $258,801 and $213,327, respectively	1,521,849	1,425,162
Fair value of derivatives assets	4,167	1,337
Intangible assets, net of accumulated amortization of $73,059 and $60,118, respectively	595,191	610,076
Goodwill	24,540	24,540
Other assets, net	8,502	9,617
Total assets	$ 2,963,343	$ 2,592,874
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable, drafts payable and accrued gas purchases	$ 738,301	$ 479,398
Fair value of derivative liabilities	47,737	21,066
Current portion of long-term debt	9,412	9,412
Other current liabilities	52,784	59,154
Total current liabilities	848,234	569,030
Long-term debt	1,245,000	1,213,706
Obligations under capital lease	14,106	3,553
Deferred tax liability	8,428	8,518
Fair value of derivative liabilities	10,237	9,426
Minority interest	4,119	3,815
Commitments and contingencies	—	—
Partners' equity	833,219	784,826
Total liabilities and partners' equity	$ 2,963,343	$ 2,592,874

See accompanying notes to condensed consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Operations

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
	(Unaudited) (In thousands, except per unit amounts)			
Revenues:				
Midstream	$ 1,524,392	$ 984,669	$ 2,776,573	$ 1,794,467
Treating	17,992	16,256	34,333	32,607
Profit on energy trading activities	281	991	1,334	1,594
Total revenues	1,542,665	1,001,916	2,812,240	1,828,668
Operating costs and expenses:				
Midstream purchased gas	1,428,930	910,061	2,582,527	1,661,943
Treating purchased gas	3,356	2,257	5,454	4,591
Operating expenses	39,640	29,956	81,545	57,313
General and administrative	17,317	14,849	32,798	26,882
Gain on sale of property	(1,381)	(971)	(1,659)	(1,821)
Gain on derivatives	(16,788)	(1,280)	(9,722)	(4,494)
Depreciation and amortization	32,740	25,509	65,242	50,495
Total operating costs and expenses	1,503,814	980,381	2,756,185	1,794,909
Operating income	38,851	21,535	56,055	33,759
Other income (expense):				
Interest expense, net	(17,211)	(18,620)	(37,321)	(35,947)
Other	478	218	7,582	268
Total other income (expense)	(16,733)	(18,402)	(29,739)	(35,679)
Income (loss) before minority interest and taxes	22,118	3,133	26,316	(1,920)
Minority interest in subsidiary	(50)	(30)	(194)	(50)
Income tax provision	(326)	(215)	(669)	(419)
Net income (loss)	$ 21,742	$ 2,888	$ 25,453	$ (2,389)
General partner interest in net income	$ 11,401	$ 4,538	$ 22,051	$ 8,707
Limited partners' interest in net income (loss)	$ 10,341	$ (1,650)	$ 3,402	$ (11,096)
Net income (loss) per limited partners' unit:				
Basic common unit	$ 0.23	$ (0.06)	$ (2.96)	$ (0.42)
Diluted common unit	$ 0.21	$ (0.06)	$ (2.96)	$ (0.42)
Basic and diluted senior subordinated series C units (see Note 4(d))	$ —	$ —	$ 9.44	$ —
Basic and diluted senior subordinated series D units (see Note 4(d))	$ —	$ —	$ —	$ —

See accompanying notes to condensed consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Changes in Partners' Equity
Six Months Ended June 30, 2008

(Unaudited)
(In thousands)

	Common Units $	Common Units Units	Subordinated Units $	Subordinated Units Units	Sr. Subordinated C Units $	Sr. Subordinated C Units Units	Sr. Subordinated D Units $	Sr. Subordinated D Units Units	General Partner Interest $	General Partner Interest Units	Accumulated Other Comprehensive Income	Total
Balance, December 31, 2007	$ 337,171	23,868	$ (14,679)	4,668	$ 359,319	12,830	$ 99,942	3,875	$ 24,551	923	$ (21,478)	$ 784,826
Issuance of common units	99,928	3,333	—	—	—	—	—	—	—	—	—	99,928
Proceeds from exercise of unit options	672	43	—	—	—	—	—	—	—	—	—	672
Conversion of subordinated units	341,816	17,498	17,503	(4,668)	(359,319)	(12,830)	—	—	—	—	—	—
Conversion of restricted units for common units, net of units withheld for taxes	(1,298)	123	—	—	—	—	—	—	—	—	—	(1,298)
Capital contributions	—	—	—	—	—	—	—	—	2,174	72	—	2,174
Stock-based compensation	3,574	—	109	—	—	—	—	—	2,683	—	—	6,366
Distributions	(42,936)	—	(2,847)	—	—	—	—	—	(20,423)	—	—	(66,206)
Net income (loss)	3,488	—	(86)	—	—	—	—	—	22,051	—	—	25,453
Hedging gains or losses reclassified to earnings	—	—	—	—	—	—	—	—	—	—	11,583	11,583
Adjustment in fair value of derivatives	—	—	—	—	—	—	—	—	—	—	(30,279)	(30,279)
Balance, June 30, 2008	$ 742,415	44,865	$ —	—	$ —	—	$ 99,942	3,875	$ 31,036	995	$ (40,174)	$ 833,219

See accompanying notes to condensed consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Comprehensive Income

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	(Unaudited) (In thousands)			
Net income (loss)	$ 21,742	$ 2,888	$ 25,453	$ (2,389)
Hedging gains (losses) reclassified to earnings	6,035	(703)	11,583	(3,277)
Adjustment in fair value of derivatives	(19,225)	967	(30,279)	(4,337)
Comprehensive income (loss)	$ 8,552	$ 3,152	$ 6,757	$ (10,003)

See accompanying notes to condensed consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Cash Flows

	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
	(Unaudited) (In thousands)	
Cash flows from operating activities:		
Net income (loss)	$ 25,453	$ (2,389)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation and amortization	65,242	50,495
Gain on sale of property	(1,659)	(1,821)
Minority interest in subsidiary	194	50
Deferred tax benefit (expense)	(127)	89
Non-cash stock-based compensation	6,366	5,086
Non-cash derivatives gain	(6,021)	(314)
Amortization of debt issue costs	1,387	1,299
Changes in assets and liabilities:		
Accounts receivable, accrued revenue and other	(249,659)	(50,190)
Natural gas and natural gas liquids, prepaid expenses and other	(18,449)	(7,105)
Accounts payable, accrued gas purchases and other accrued liabilities	263,905	52,576
Fair value of derivatives	—	835
Net cash provided by operating activities	86,632	48,611
Cash flows from investing activities:		
Additions to property and equipment	(151,251)	(229,857)
Proceeds from sale of property	3,769	2,819
Net cash used in investing activities	(147,482)	(227,038)
Cash flows from financing activities:		
Proceeds from borrowings	717,300	751,500
Payments on borrowings	(686,006)	(604,806)
Proceeds from capital lease obligations	12,258	—
Payments on capital lease obligations	(405)	—
Decrease in drafts payable	(10,540)	(30,309)
Debt refinancing costs	(233)	(411)
Restricted units withheld for taxes	(1,298)	(186)
Distribution to partners	(66,206)	(42,043)
Proceeds from exercise of unit options	672	1,401
Net proceeds from common unit offering	99,928	—
Issuance of subordinated units	—	99,942
Contributions from partners	2,174	2,771
Contributions from minority interest	109	—
Net cash provided by financing activities	67,753	177,859
Net increase (decrease) in cash and cash equivalents	6,903	(568)
Cash and cash equivalents, beginning of period	142	824
Cash and cash equivalents, end of period	$ 7,045	$ 256
Cash paid for interest	$ 37,070	$ 37,223
Cash paid for income taxes	$ 1,102	$ 10

See accompanying notes to condensed consolidated financial statements.

Notes to Condensed Consolidated Financial Statements
June 30, 2008
(Unaudited)

(1) General

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

Crosstex Energy, L.P., a Delaware limited partnership formed on July 12, 2002, is engaged in the gathering, transmission, 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 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, and transports 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 a 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. These condensed consolidated financial statements should be read in conjunction with the financial statements and notes thereto included in our annual report on Form 10-K for the year ended December 31, 2007.

(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) 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 No. 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, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
Cost of share-based compensation charged to general and administrative expense	$ 3,255	$ 2,406	$ 5,486	$ 4,429
Cost of share-based compensation charged to operating expense	481	446	880	657
Total amount charged to income	$ 3,736	$ 2,852	$ 6,366	$ 5,086

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, 2008 is provided below:

Crosstex Energy, L.P. Restricted Units:	Six Months Ended June 30, 2008 Number of Units	Six Months Ended June 30, 2008 Weighted Average Grant-Date Fair Value
Non-vested, beginning of period	504,518	$ 34.27
Granted	328,675	30.64
Vested	(166,120)	32.72
Forfeited	(17,905)	26.94
Non-vested, end of period	649,168	$ 33.03
Aggregate intrinsic value, end of period (in thousands)	$ 18,618	

During the six months ended June 30, 2008, the Partnership's executive officers were granted restricted units, the number of which may increase or decrease based on the accomplishment of certain performance targets. The target number of restricted units for all executives of 175,982 for 2008 will be increased (up to a maximum of 300% of the target number of units) or decreased (to a minimum of 30% of the target number of units) based on the Partnership's average growth rate (defined as the percentage increase or decrease in distributable cash flow per common unit over the three-year period from January 2008 through January 2011) for grants issued in 2008 compared to the Partnership's target three-year average growth rate of 9.0%. The restricted unit activity for the six months ended June 30, 2008 reflects the 175,982 performance-based restricted unit grants for executive officers based on current performance models. The performance-based restricted units are included in the current share-based compensation calculations as required by SFAS No. 123(R) when it is deemed probable of achieving the performance criteria. All performance-based awards greater than the minimum performance grants will be subject to reevaluation and adjustment until the restricted units vest.

The aggregate intrinsic value of units vested during the six month period ended June 30, 2008 and 2007 was $5.2 million and $0.7 million, respectively. The intrinsic value of units vested during the three months ended June 30, 2008 and 2007 was $1.2 million and $0.7 million, respectively. The total fair value of units vested during the six months ended June 30, 2008 and 2007 was $5.4 million and $0.3 million, respectively. The total fair value of units vested for the three months ended June 30, 2008 and 2007 was $0.7 million and $0.3 million, respectively. As of June 30, 2008, there was $13.0 million of unrecognized compensation cost related to non-vested restricted units. That cost is expected to be recognized over a weighted-average period of 2.4 years.

Unit Options

The following weighted average assumptions were used for the Black-Scholes option pricing model for grants during the three and six months ended June 30, 2008 and 2007:

Crosstex Energy, L.P. Unit Options Granted:	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
Weighted average distribution yield	5.75%	7.15%	5.75%
Weighted average expected volatility	32%	30%	32%
Weighted average risk free interest rate	4.44%	1.81%	4.44%
Weighted average expected life	6 years	6 years	6 years
Weighted average contractual life	10 years	10 years	10 years
Weighted average of fair value of unit options granted	$5.92	$3.49	$6.76

There were no options granted during the three months ended June 30, 2008.

A summary of the unit option activity for the six months ended June 30, 2008 is provided below:

Crosstex Energy, L.P. Unit Options:	Six Months Ended June 30, 2008 Number of Units	Six Months Ended June 30, 2008 Weighted Average Exercise Price
Outstanding, beginning of period	1,107,309	$ 29.65
Granted	400,011	31.58
Exercised	(41,278)	15.71
Forfeited	(49,513)	30.39
Expired	(39,160)	34.33
Outstanding, end of period	1,377,369	$ 30.47
Options exercisable at end of period	559,602	
Weighted average contractual term (years) end of period:		
Options outstanding	7.8	
Options exercisable	6.9	
Aggregate intrinsic value end of period (in thousands):		
Options outstanding	$ 3,094	
Options exercisable	$ 2,228	

The total intrinsic value of unit options exercised during the six months ended June 30, 2008 and 2007 was $0.7 million and $1.4 million, respectively. The intrinsic value of unit options exercised during the three months ended June 30, 2008 and 2007 was $0.5 million and $0.9 million, respectively. The total fair value of units vested during the six months ended June 30, 2008 and 2007 was $0.9 million and $0.3 million, respectively. The total fair value of units vested for the three months ended June 30, 2008 and 2007 was $0.8 million and $0.1 million, respectively. As of June 30, 2008, there was $2.6 million of unrecognized compensation cost related to non-vested unit options. That cost is expected to be recognized over a weighted average period of 1.7 years.

CEI Restricted Shares

CEI's restricted shares are included 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, 2008 is provided below:

	Six Months Ended June 30, 2008	
Crosstex Energy, Inc. Restricted Shares:	**Number of Shares**	**Weighted Average Grant-Date Fair Value**
Non-vested, beginning of period	860,275	$ 21.59
Granted	304,987	33.46
Vested*	(336,402)	17.46
Forfeited	(52,113)	19.57
Non-vested, end of period	776,747	$ 28.18
Aggregate intrinsic value, end of period (in thousands)	$ 26,922	

* Vested shares include 96,957 shares withheld for payroll taxes paid on behalf of employees.

During the six months ended June 30, 2008, the Partnership's executive officers were granted restricted shares the number of which may increase or decrease based on the accomplishment of certain performance targets. The target number of restricted shares for all executives of 166,791 for 2008 will be increased (up to a maximum of 300% of the target number of units) or decreased (to a minimum of 30% of the target number of units) based on the Partnership's average growth rate (defined as the percentage increase or decrease in distributable cash flow per common unit over the three-year period from January 2008 through January 2011) for grants issued in 2008 compared to the Partnership's target three-year average growth rate of 9.0%. The restricted share activity for the six months ended June 30, 2008 reflects the 166,791 performance-based restricted share grants for executive officers based on current performance models. The performance-based restricted shares are included in the current share-based compensation calculations as required by SFAS No. 123(R) when it is deemed probable of achieving the performance criteria. All performance-based awards greater than the minimum performance grants will be subject to reevaluation and adjustment until the restricted shares vest.

The aggregate intrinsic value of vested shares for the six months ended June 30, 2008 and 2007 was $12.4 million and $1.4 million, respectively. The intrinsic value of vested shares for the three months ended June 30, 2008 was $0.7 million. The fair value of shares vested during the six months ended June 30, 2008 and 2007 was $5.9 million and $0.5 million, respectively. The fair value of shares vested during the three months ended June 30, 2008 was $0.6 million. There were no shares vested for the three months ended June 30, 2007. As of June 30, 2008, there was $11.7 million of unrecognized compensation costs related to non-vested CEI restricted stock. The cost is expected to be recognized over a weighted average period of 2.4 years.

CEI Options

No CEI stock options were granted to, or exercised or forfeited by any officers or employees of the Partnership during the three and six months ended June 30, 2008 and 2007. The following is a summary of the CEI stock options outstanding attributable to officers and employees of the Partnership as of June 30, 2008:

Outstanding stock options (7,500 exercisable)		30,000
Weighted average exercise price	$	13.33
Aggregate intrinsic value outstanding	$	639,800
Aggregate intrinsic value exercisable	$	185,588
Weighted average remaining contractual term		6.5 years

There were no shares vested during the three months and six months ended June 30, 2008 and 2007. As of June 30, 2008, there was approximately $26,000 of unrecognized compensation costs related to non-vested CEI stock options. The cost is expected to be recognized over a weighted average period of 1.3 years.

(c) Recent Accounting Pronouncements

In May 2008, the Financial Accounting Standards Board (FASB) issued Staff Position FSP EITF 03-6-1 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. Upon adoption, the Partnership will consider restricted units with nonforfeitable distribution rights in the calculation of earnings per unit and will adjust all prior reporting periods retrospectively to conform to the requirements although the impact should not be material.

In February 2007, the FASB issued SFAS No. 159, *"Fair Value Option for Financial Assets and Financial Liabilities-Including an amendment to FASB Statement No. 115"* (SFAS 159). SFAS 159 permits entities to choose to measure many financial assets and financial liabilities at fair value. Changes in the fair value on items for which the fair value option has been elected are recognized in earnings each reporting period. SFAS 159 also establishes presentation and disclosure requirements designed to draw comparisons between the different measurement attributes elected for similar types of assets and liabilities. SFAS 159 was adopted effective January 1, 2008 and did not have a material impact on our financial statements.

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 will require 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. The statement applies to the accounting for noncontrolling interests and transactions with noncontrolling interest holders in consolidated financial statements. SFAS 160 is effective for periods beginning on or after December 15, 2008 and will be applied prospectively to all noncontrolling interests, including any that arose before the effective date except that comparative period information must be recast to classify noncontrolling interests in equity, attribute net income and other comprehensive income to noncontrolling interests, and provide other disclosures required by SFAS 160.

In March of 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. The principal impact to the Partnership will be to require expanded disclosure regarding derivative instruments.

(2) Long-Term Debt

As of June 30, 2008 and December 31, 2007, long-term debt consisted of the following (in thousands):

	June 30, 2008	December 31, 2007
Bank credit facility, interest based on Prime and/or LIBOR plus an applicable margin, interest rates (per the facility) at June 30, 2008 and December 31, 2007 were 5.51% and 6.71%, respectively	$ 770,000	$ 734,000
Senior secured notes, weighted average interest rate at June 30, 2008 and December 31, 2007 was 6.75%	484,412	489,118
	1,254,412	1,223,118
Less current portion	(9,412)	(9,412)
Debt classified as long-term	$ 1,245,000	$ 1,213,706

Credit Facility. As of June 30, 2008, the Partnership has a bank credit facility with a borrowing capacity of $1.185 billion that matures in June 2011. As of June 30, 2008, $939.8 million was outstanding under the bank credit facility, including $169.8 million of letters of credit, leaving approximately $245.2 million available for future borrowing. The bank credit facility is guaranteed by certain of our subsidiaries.

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 (5) to the financial statements for a discussion of interest rate swaps.

The Partnership was in compliance with all debt covenants as of June 30, 2008 and expects to be in compliance with debt covenants for the next twelve months.

(3) Other Long-Term Liabilities

The Partnership entered into 9 and 10-year capital leases for certain compressor equipment. Assets under capital leases as of June 30, 2008 are summarized as follows (in thousands):

Compressor equipment	$ 16,269
Less: Accumulated amortization	(506)
Net assets under capital lease	$ 15,763

The following are the minimum lease payments to be made in the following years indicated for the capital lease in effect as of June 30, 2008 (in thousands):

2008 through 2012	$ 7,950
Thereafter	10,883
Less: Interest	(2,992)
Net minimum lease payments under capital lease	15,841
Less: Current portion of net minimum lease payments	(1,735)
Long-term portion of net minimum lease payments	$ 14,106

(4) Partners' Capital

(a) Issuance of Common Units

On April 9, 2008, the Partnership issued 3,333,334 common units in a private offering at $30.00 per unit, which represented an approximate 7% discount from the market price. Net proceeds from the issuance, including the general partner's proportionate capital contribution and expenses associated with the issuance, were approximately $102.0 million.

(b) Conversion of Subordinated and Senior Subordinated Series C Units

The subordination period for the Partnership's subordinated units ended and the remaining 4,668,000 subordinated units converted into common units representing limited partner interests of the Partnership effective February 16, 2008.

The 12,829,650 senior subordinated series C units of the Partnership also converted into common units representing limited partner interests of the Partnership effective February 16, 2008. See Note (4)(d) below for a discussion of the impact on earnings per unit resulting from the conversion of the senior subordinated series C units.

(c) Cash Distributions

In accordance with the partnership agreement, the Partnership must make distributions of 100% of available cash, as defined in the partnership agreement, within 45 days following the end of each quarter. Distributions will generally be made 98% to the common and subordinated unitholders and 2% 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% of amounts we distribute in excess of $0.25 per unit, 23% of the amounts we distribute in excess of $0.3125 per unit and 48% of amounts we distribute in excess of $0.375 per unit. Incentive distributions totaling $12.3 million and $5.8 million were earned by our general partner for the three months ended June 30, 2008 and June 30, 2007, respectively. Incentive distributions totaling $24.1 million and $11.3 million were earned in the six month period ended June 30, 2008 and June 30, 2007, respectively.

The Partnership has declared a second quarter 2008 distribution of $0.63 per unit to be paid on August 15, 2008 to unitholders of record as of August 4, 2008.

(d) 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 such subordination periods when the criteria for conversion are met. Following is a summary of the BCFs attributable to the senior subordinated units outstanding during 2007 and 2008 (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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
Limited partners' interest in net income (loss)	$ 10,341	$ (1,650)	$ 3,402	$ (11,096)
Distributed earnings allocated to:				
Common units(1)	$ 40,726	$ 15,290	$ 63,359	$ 30,210
Senior subordinated series C units(2)	—	—	121,112	—
Total distributed earnings	$ 40,726	$ 15,290	$ 184,471	$ 30,210
Undistributed loss allocated to:				
Common units(3)	$ (30,385)	$ (16,940)	(181,069)	$ (41,306)
Senior subordinated series C units	—	—	—	—
Total undistributed earnings (loss)	$ (30,385)	$ (16,940)	$ (181,069)	$ (41,306)
Net income (loss) allocated to:				
Common units	$ 10,341	$ (1,650)	$ (117,710)	$ (11,096)
Senior subordinated series C units	—	—	121,112	—
Total limited partners' interest in net income (loss)	$ 10,341	$ (1,650)	$ 3,402	$ (11,096)
Basic and diluted net income (loss) per unit:				
Basic common units	$ 0.23	$ (0.06)	$ (2.96)	$ (0.42)
Diluted common units	$ 0.21	$ (0.06)	$ (2.96)	$ (0.42)
Senior subordinated series C units	$ —	$ —	$ 9.44	$ —
Senior subordinated series D units	$ —	$ —	$ —	$ —

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

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

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

The following are the unit amounts used to compute the basic and diluted earnings per limited partner common unit and senior subordinated series C unit for the three and six months ended June 30, 2008 and 2007 (in thousands):

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
Basic earnings per unit:				
Weighted average limited partner common units outstanding	44,510	26,685	39,745	26,664
Diluted earnings per unit:				
Weighted average limited partner units outstanding	44,510	26,685	39,745	26,664
Dilutive effect of restricted units issued	153	—	—	—
Dilutive effect of senior subordinated units	3,875	—	—	—
Dilutive effect of exercise of options outstanding	131	—	—	—
Diluted common units	48,669	26,685	39,745	26,664
Weighted average diluted senior subordinated series C units outstanding	—	—	12,830	—

All common equivalents were antidilutive in the six months ended June 30, 2008 and in the three and six months ended June 30, 2007 because the limited partners were allocated a net loss in the periods.

Net income for the general partner consists of incentive distributions, a deduction for stock-based compensation related to CEI, 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 after these allocations relates to common and subordinated units (excluding senior subordinated). The net income allocated to the general partner is as follows (in thousands):

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
Income allocation for incentive distributions	$ 12,272	$ 5,767	$ 24,098	$ 11,264
Stock-based compensation attributable to CEI's stock options and restricted shares	(1,573)	(1,195)	(2,608)	(2,330)
2% general partner interest in net income (loss)	702	(34)	561	(227)
General Partner share of net income	$ 11,401	$ 4,538	$ 22,051	$ 8,707

(5) Derivatives

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 has entered into eight interest rate swaps as of June 30, 2008 as shown below:

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 $50,000,000 with the same original term.

Each swap fixes 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. The Partnership also entered into one new swap in January 2008.

The Partnership had previously elected to designate all interest rate swaps (except the November 2006 swap) as cash flow hedges for FAS 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 dedesignated as cash flow hedges. The net present value of the unrealized loss in accumulated other comprehensive income of $17.0 million at the dedesignation dates is being reclassified to earnings over the remaining original terms of the swaps using the effective interest method. The related loss reclassified to earnings and included in “(Gain) loss on derivatives” during the three and six months ended June 30, 2008 is $1.3 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 FAS 133 treatment. Accordingly, unrealized gains and losses are recorded through the consolidated statement of operations in (gain)/loss on derivatives over the period hedged.

The components of (gain)/loss on derivatives in the consolidated statements of operations relating to interest rate swaps are (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
Change in fair value of derivatives that do not qualify for hedge accounting	$ (13,977)	$ (480)	$ (6,063)	$ (285)
Realized (gain) loss on derivatives	1,780	(111)	1,964	(181)
Ineffective portion of derivatives qualifying for hedge accounting	—	—	—	—
	$ (12,197)	$ (591)	$ (4,099)	$ (466)

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

	June 30, 2008	December 31, 2007
Fair value of derivative assets — current	$ 86	$ 68
Fair value of derivative assets — long-term	—	—
Fair value of derivative liabilities — current	(7,314)	(3,266)
Fair value of derivative liabilities — long-term	(2,494)	(8,057)
Net fair value of derivatives	$ (9,722)	$ (11,255)

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” and “processing margin 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 frac spread risk at our processing plants relating to the option to process versus bypassing our equity gas.

The components of (gain)/loss on derivatives in the consolidated statements of operations, excluding interest rate swaps, are (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
Change in fair value of derivatives that do not qualify for hedge accounting	$ (1,665)	$ 607	$ (812)	$ (76)
Realized (gain) loss on derivatives	(3,007)	(1,331)	(4,946)	(4,016)
Ineffective portion of derivatives qualifying for hedge accounting	81	35	135	64
	$ (4,591)	$ (689)	$ (5,623)	$ (4,028)

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

	June 30, 2008	December 31, 2007
Fair value of derivative assets — current	$ 20,481	$ 8,521
Fair value of derivative assets — long term	4,167	1,337
Fair value of derivative liabilities — current	(40,423)	(17,800)
Fair value of derivative liabilities — long term	(7,743)	(1,369)
Net fair value of derivatives	$ (23,518)	$ (9,311)

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, 2008 (all gas volumes are expressed in MMBtu's and all liquids are expressed in gallons). The remaining term of the contracts extend no later than June 2010 for derivatives except for certain basis swaps that extend to March 2012. The Partnership's counterparties to hedging contracts include BP Corporation, Total Gas & Power, Fortis, Morgan Stanley, J. Aron & Co., a subsidiary of Goldman Sachs, Sempra Energy and Mitsui & Co. 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.

June 30, 2008		
Transaction Type	Volume	Fair Value
	(In thousands)	
Cash Flow Hedges:		
Natural gas swaps (short contracts) (MMBtu's)	(1,596)	$ (7,017)
Liquids swaps (short contracts) (gallons)	(32,189)	(19,325)
Total swaps designated as cash flow hedges		$ (26,342)
*Mark to Market Derivatives:**		
Swing swaps (short contracts)	(930)	$ 19
Physical offsets to swing swap transactions (long contracts)	930	—
Swing swaps (long contracts)	1,031	34
Physical offsets to swing swap transactions (short contracts)	(1,031)	2
Basis swaps (long contracts)	69,855	1,895
Physical offsets to basis swap transactions (short contracts)	(17,479)	119,897
Basis swaps (short contracts)	(63,335)	(2,464)
Physical offsets to basis swap transactions (long contracts)	9,385	(116,853)
Third-party on-system financial swaps (long contracts)	4,130	16,163
Physical offsets to third-party on-system transactions (short contracts)	(4,130)	(15,930)
Third-party on-system financial swaps (short contracts)	(665)	(263)
Physical offsets to third-party on-system transactions (long contracts)	665	305
Third-party off-system financial swaps (short contracts)	(460)	(2,350)
Physical offsets to third-party off-system transactions (long contracts)	460	2,382
Storage swap transactions (short contracts)	(170)	(13)
Total mark to market derivatives		$ 2,824

* All are gas contracts, volume in MMBtu's

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.

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):

Increase (Decrease) in Midstream Revenue	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
Natural gas	$ (1,120)	$ 1,173	$ 120	$ 2,748
Liquids	(5,698)	(764)	(10,935)	(248)
	$ (6,818)	$ 409	$ (10,815)	$ 2,500

Natural Gas

As of June 30, 2008, an unrealized derivative fair value loss of $6.9 million, related to cash flow hedges of gas price risk, was recorded in accumulated other comprehensive income (loss). Of this net amount, a $5.8 million loss is expected to be reclassified into earnings through June 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 2008 gas production decreased gas revenue by approximately $0.7 million.

Liquids

As of June 30, 2008, an unrealized derivative fair value loss of $19.2 million related to cash flow hedges of liquids price risk was recorded in accumulated other comprehensive income (loss). Of this amount, a $16.5 million loss is expected to be reclassified into earnings through June 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.

Derivatives Other Than Cash Flow Hedges

Assets and liabilities related to third party derivative contracts, puts, 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 prices actively quoted. 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, 2008	$ 2,522	$ 302	—	$ 2,824

(6) Fair Value Measurements

In September 2006, the FASB issued SFAS No. 157, *"Fair Value Measurements"* (SFAS 157). SFAS 157 introduces a framework for measuring fair value and expands required disclosure about fair value measurements of assets and liabilities. SFAS 157 for financial assets and liabilities is effective for fiscal years beginning after

November 15, 2007, and the Partnership has adopted the standard for those assets and liabilities as of January 1, 2008 and the impact of adoption was not significant.

Fair value 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.

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

	Total	Level 1	Level 2	Level 3
Interest Rate Swaps*	$ 9,722	—	$ 9,722	—
Commodity Swaps*	23,518	—	23,518	—
Total	$ 33,240	—	$ 33,240	—

* Unrealized gains or losses on commodity derivatives qualifying for hedge accounting are recorded in accumulated other comprehensive income (loss) at each measurement date. Accumulated other comprehensive income also includes the net present value of unrealized losses on interest rate swaps of $17.0 million recorded prior to dedesignation in January 2008, of which $3.0 million has been amortized to earnings through June 2008.

(7) 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.

(8) 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) Environmental Issues

The Partnership did not have any change in environmental quality issues in the six months ended June 30, 2008.

(c) Other

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

On November 15, 2007, Crosstex CCNG Processing Ltd. (Crosstex CCNG), a wholly-owned subsidiary of the Partnership, 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. The claim arises from a contract under which Crosstex CCNG processed natural gas owned or controlled by Denbury in north Texas. Denbury contends that Crosstex CCNG breached the contract by failing to build a processing plant of a certain size and design, resulting in Crosstex CCNG's failure to properly process the gas over a ten month period. Denbury also alleges that Crosstex CCNG failed to provide specific notices required under the contract. On December 4, 2007 and February 14, 2008, Denbury sent Crosstex CCNG letters requesting that its claim be arbitrated pursuant to an arbitration provision in the contract. Although it is not possible to predict with certainty the ultimate outcome of this matter, we do not believe this will have a material adverse impact on our consolidated results of operations or financial position.

The Partnership (or its subsidiaries) is defending several lawsuits filed by owners of property located near processing facilities or compression facilities constructed by the Partnership as part of its systems in North Texas. 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, SemGroup, 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, SemGroup, L.P. owed the Partnership approximately $6.3 million, including approximately $3.9 million for June 2008 sales and approximately $2.3 million for July 2008 sales. In addition, the Partnership believes the July sales of $2.3 million will receive "administrative claim" status in the bankruptcy proceeding. The Partnership will evaluate these receivables for collectibility and provide a valuation allowance, as deemed necessary, during the quarter ended September 30, 2008.

(9) 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 processing and transmission assets located in north and south Texas, the LIG pipelines and processing plants located in Louisiana, the Mississippi System, the Arkoma system located in Oklahoma 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. The Seminole carbon dioxide processing plant located in Gaines County, Texas is included in the Treating division. The operators of the Seminole plant are expanding the facility and the Partnership has chosen to participate in the expansion. As a result, capital expenditures in the Treating segment are up approximately $4.9 million in the first half of 2008 and are expected to continue through first quarter of 2009 when the expansion is expected to complete.

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.

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

	Midstream	Treating	Corporate	Totals
		(In thousands)		
Three months ended June 30, 2008:				
Sales to external customers	$ 1,524,392	$ 17,992	$ —	$ 1,542,384
Sales to affiliates	3,680	1,650	(5,330)	—
Profit on energy trading activities	281	—	—	281
Purchased gas	(1,432,610)	(3,356)	3,680	(1,432,286)
Operating expenses	(34,498)	(6,792)	1,650	(39,640)
Segment profit	$ 61,245	$ 9,494	$ —	$ 70,739
Gain (loss) on derivatives	$ 4,595	$ (4)	$ 12,197	$ 16,788
Depreciation and amortization	$ (27,340)	$ (3,620)	$ (1,780)	$ (32,740)
Capital expenditures (excluding acquisitions)	$ 57,298	$ 15,377	$ 2,864	$ 75,539
Identifiable assets	$ 2,679,260	$ 228,623	$ 55,460	$ 2,963,343
Three months ended June 30, 2007:				
Sales to external customers	$ 984,669	$ 16,256	$ —	$ 1,000,925
Sales to affiliates	2,492	1,173	(3,665)	—
Profit on energy trading activities	991	—	—	991
Purchased gas	(912,553)	(2,257)	2,492	(912,318)
Operating expenses	(25,624)	(5,505)	1,173	(29,956)
Segment profit	$ 49,975	$ 9,667	$ —	$ 59,642
Gain (loss) on derivatives	$ 1,507	$ (4)	$ (223)	$ 1,280
Depreciation and amortization	$ (21,331)	$ (3,377)	$ (801)	$ (25,509)
Capital expenditures (excluding acquisitions)	$ 119,429	$ 2,590	$ 1,195	$ 123,214
Identifiable assets	$ 2,176,864	$ 208,228	$ 28,669	$ 2,413,761
Six months ended June 30, 2008:				
Sales to external customers	$ 2,776,573	$ 34,333	—	$ 2,810,906
Sales to affiliates	6,237	3,190	(9,427)	—
Profit on energy trading activities	1,334	—	—	1,334
Purchased gas	(2,588,764)	(5,454)	6,237	(2,587,981)
Operating expenses	(69,817)	(14,918)	3,190	(81,545)
Segment profit	$ 125,563	$ 17,151	$ —	$ 142,714
Gain (loss) on derivatives	$ 5,627	$ (4)	$ 4,099	$ 9,722
Depreciation and amortization	$ (54,402)	$ (7,344)	$ (3,496)	$ (65,242)
Capital expenditures (excluding acquisitions)	$ 122,661	$ 22,126	$ 4,398	$ 149,185
Identifiable assets	$ 2,679,260	$ 228,623	$ 55,460	$ 2,963,343
Six months ended June 30, 2007:				
Sales to external customers	$ 1,794,467	$ 32,607	$ —	$ 1,827,074
Sales to affiliates	5,138	2,212	(7,350)	—
Profit on energy trading activities	1,594	—	—	1,594
Purchased gas	(1,667,081)	(4,591)	5,138	(1,666,534)
Operating expenses	(48,769)	(10,756)	2,212	(57,313)
Segment profit	$ 85,349	$ 19,472	$ —	$ 104,821
Gain (loss) on derivatives	$ 4,855	$ (14)	$ (347)	$ 4,494
Depreciation and amortization	$ (41,121)	$ (7,303)	$ (2,071)	$ (50,495)
Capital expenditures (excluding acquisitions)	$ 210,799	$ 13,014	$ 2,747	$ 226,560
Identifiable assets	$ 2,176,864	$ 208,228	$ 28,669	$ 2,413,761

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,	
	2008	2007	2008	2007
Segment profits	$ 70,739	$ 59,642	$ 142,714	$ 104,821
General and administrative expenses	(17,317)	(14,849)	(32,798)	(26,882)
Gain (loss) on derivatives	16,788	1,280	9,722	4,494
Gain (loss) on sale of property	1,381	971	1,659	1,821
Depreciation and amortization	(32,740)	(25,509)	(65,242)	(50,495)
Operating income	$ 38,851	$ 21,535	$ 56,055	$ 33,759

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 along the Texas Gulf Coast, in the north Texas Barnett Shale area, and in Louisiana and Mississippi. 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, 2008, 87% 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 and NGLs for a margin, or to gather, process, transport, market or treat 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 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. As explained under "Commodity Price Risk" below, we enter into financial instruments to reduce volatility in our gross margin due to price fluctuations.

Our Midstream segment margins are determined primarily by the volumes of natural gas gathered, transported, purchased and sold through our pipeline systems, 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 and fees earned for removing impurities at a non-operated processing plant. We generate revenues from five primary sources:

- purchasing and reselling or transporting natural gas on the pipeline systems we own;
- processing natural gas at our processing plants and fractionating and marketing the recovered NGLs;
- treating natural gas at our treating plants;
- recovering carbon dioxide and NGLs at a non-operated processing plant; and
- providing off-system marketing services for producers.

The bulk of our operating profits has historically been derived from the margins we realize for gathering and transporting natural gas through our pipeline systems. Generally, we buy gas from a producer, plant or transporter at either a fixed discount to a market index or a percentage of the market index. We then transport and resell the gas. 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. See "Commodity Price Risk" below for a discussion of how we manage our business to reduce the impact of price volatility.

Processing revenues are generally based on either a percentage of the liquids volume recovered, or a margin based on the value of liquids recovered less the reduced energy value in the remaining gas after the liquids are removed, or a fixed fee per unit processed. Fractionation and marketing fees are generally a fixed fee per unit of products.

We generate treating revenues under three arrangements:

- a volumetric fee based on the amount of gas treated, which accounted for approximately 28% and 27%, including the Seminole plant, of the operating income in our Treating division for the six months ended June 30, 2008 and 2007, respectively;

- a fixed fee for operating the plant for a certain period, which accounted for approximately 51% and 49% of the operating income in our Treating division for the six months ended June 30, 2008 and 2007, respectively; or
- a fee arrangement in which the producer operates the plant, which accounted for approximately 21% and 24% of the operating income in our Treating division for the six months ended June 30, 2008 and 2007, 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.

Expansions

During the first half of 2008, we continued the expansion of our north Texas pipeline gathering system in the Barnett Shale which was acquired in June 2006. Since the date of acquisition through June 30, 2008, we connected approximately 375 new wells to our gathering system including approximately 89 new wells connected during the first half of 2008. Our total throughput on the north Texas gathering systems, including throughput on our north Johnson County expansion discussed below, was approximately 690,000 MMBtu/d for the month of June 2008, up from a monthly throughput of approximately 525,000 MMBtu/d in December 2007.

We continued the construction of our 29-mile north Johnson County expansion, which is part of our north Texas pipeline gathering system, during the first half of 2008. The first phase of this expansion commenced operation in September 2007. The last two phases of the expansion commenced operation in May and July of 2008. The total gathering capacity for this 29-mile expansion is approximately 400 MMcf/d.

We also completed our east Texas natural gas gathering system expansion in May of 2008. We added a new pipeline next to our existing system which increased capacity to approximately 100 MMcf/d and added two refrigeration plants to improve its ability to process the gas.

On April 28, 2008, we announced plans to construct an $80 million natural-gas processing facility called Bear Creek in the Barnett Shale region of north Texas. The new plant, which is expected to become operational in the third quarter of 2009, will have a gas processing capacity of 200 MMcf/d, increasing our total processing capacity in the Barnett Shale to 485 MMcf/d. The Bear Creek plant will be strategically located near our existing midstream assets in Hood County.

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.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	(Dollars in millions)			
Midstream revenues	$ 1,524.4	$ 984.7	$ 2,776.6	$ 1,794.4
Midstream purchased gas	(1,428.9)	(910.1)	(2,582.5)	(1,661.9)
Profit on energy trading activities	0.2	1.0	1.3	1.6
Midstream gross margin	95.7	75.6	195.4	134.1
Treating revenues	18.0	16.3	34.3	32.6
Treating purchased gas	(3.3)	(2.3)	(5.4)	(4.6)
Treating gross margin	14.7	14.0	28.9	28.0
Total gross margin	$ 110.4	$ 89.6	$ 224.3	$ 162.1
Midstream Volumes (MMBtu/d):				
Gathering and transportation	2,604,000	2,113,000	2,572,000	1,943,000
Processing	2,121,000	2,109,000	2,169,000	2,050,000
Producer services	90,000	100,000	85,000	95,000
Plants in service at end of period	190	195	190	195

Three Months Ended June 30, 2008 Compared to Three Months Ended June 30, 2007

Gross Margin and Profit on Energy Trading Activities. Midstream gross margin was $95.7 million for the three months ended June 30, 2008 compared to $75.6 million for the three months ended June 30, 2007, an increase of $20.1 million, or 26.6%. This increase was primarily due to system expansion projects and increased throughput. Profit on energy trading activities decreased for the comparative period.

System expansion in the north Texas region and increased throughput on the North Texas Pipeline (NTP) contributed $15.1 million of gross margin growth for the three months ended June 30, 2008 over the same period in 2007. The gathering systems in the region and NTP accounted for $10.0 million and $2.4 million of this increase, respectively. The processing facilities in the region contributed an additional $2.7 million of this gross margin increase. System expansion and volume increases on the LIG system contributed margin growth of $2.1 million during the second quarter of 2008 over the same period in 2007. The south Texas region had a margin increase of $1.9 million for the comparative periods primarily due to growth on the Vanderbilt system. Processing plants in Louisiana contributed margin growth of $1.3 million for the comparative three month periods due to higher NGL prices and increased volumes at the Gibson and Plaquemine plants and the Riverside fractionation facility. These gains were partially offset by volume declines at the Eunice and Pelican plants.

Treating gross margin was $14.7 million for the three months ended June 30, 2008 compared to $14.0 million in the same period in 2007, an increase of $0.6 million, or 4.6%. There were approximately 190 treating and dew point control plants in service at June 30, 2008, which is a slight decrease from the 195 in service at June 30, 2007. However, gross margin increased slightly due to larger plants being in service. Field services provided to producers contributed $0.4 million in gross margin growth between comparative three month periods.

Operating Expenses. Operating expenses were $39.6 million for the three months ended June 30, 2008 compared to $30.0 million for the three months ended June 30, 2007, an increase of $9.7 million, or 32.3%. Midstream operating expenses have increased primarily due to expansion and growth of our midstream assets in the NTP, NTG, north Louisiana and east Texas areas, and increased costs for chemicals, materials and supplies and fuel also contributed to the increase. Contractor services and labor costs increased by $2.7 million in the second quarter of 2008 over the same three month period in 2007. Compressor rentals and related costs increased by $1.9 million and chemicals, materials and supplies and fuel costs increased by $2.4 million. Ad valorem taxes increased by $0.6 million due to our growth. Treating operating expenses increased by $1.3 million for the three month period ended June 30, 2008 compared to the three month period ended June 30, 2007. We experienced similar cost increases on chemicals, materials and supplies, and fuel in our treating operations contributing to a $0.6 million increase between periods. Labor costs increased by $0.3 million as a result of market adjustments for field service employees and additional headcount. Contractor services costs to support maintenance projects contributed to the remaining increase in operating expenses of $0.4 million. Operating expenses included $0.5 million of stock-based compensation expense for the three months ended June 30, 2008 compared to $0.4 million of stock-based compensation expense for the three months ended June 30, 2007.

General and Administrative Expenses. General and administrative expenses were $17.3 million for the three months ended June 30, 2008 compared to $14.8 million for the three months ended June 30, 2007, an increase of $2.5 million, or 16.6%. A substantial part of the increase resulted from staffing related costs of $1.2 million. Staff additions associated with the expansions of the NTG assets, NTP and the north Louisiana system accounted for the majority of the $1.2 million increase. Rental expense increased $0.5 million over the same period in 2007 due to the addition of office rent for the expansion of corporate headquarters. General and administrative expenses included stock-based compensation expense of $3.2 million and $2.4 million for the three months ended June 30, 2008 and 2007, respectively. The $0.8 million increase in stock-based compensation primarily relates to increased staffing and additional grants for comparative periods.

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. The $1.0 million gain on property sold during the three months ended June 30, 2007 primarily related to the disposition of unused catalyst material.

Gain/Loss on Derivatives. We had a gain on derivatives of $16.8 million for the three months ended June 30, 2008 compared to a gain of $1.3 million for the three months ended June 30, 2007. The derivative transaction types contributing to the net gain are as follows:

	Three Months Ended June 30,			
	2008		2007	
(Gain)/Loss on Derivatives	Total	Realized	Total	Realized
	(In millions)			
Interest rate swaps	$ (12.2)	$ 1.8	$ (0.6)	—
Basis swaps	(3.4)	(1.7)	(1.5)	(1.9)
Third-party on system swaps	(1.3)	—	—	—
Processing margin hedges	—	—	1.0	0.7
Other	0.1	—	(0.2)	—
	$ (16.8)		$ (1.3)	

Depreciation and Amortization. Depreciation and amortization expenses were $32.7 million for the three months ended June 30, 2008 compared to $25.5 million for the three months ended June 30, 2007, an increase of $7.2 million, or 28.3%. Midstream depreciation and amortization increased $6.0 million primarily due to the north Texas expansion. Software additions and depreciation acceleration of Dallas office leasehold improvements accounted for an increase between periods of $0.8 million.

Interest Expense. Interest expense was $17.2 million for the three months ended June 30, 2008 compared to $18.6 million for the three months ended June 30, 2007, a decrease of $1.4 million, or 7.6%. The decrease relates primarily to lower interest rates between three-month periods (weighted average rate of 6.1% in the 2008 period compared to 7.0% in the 2007 period). Net interest expense consists of the following (in millions):

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007
Senior notes	$ 8.2	$ 8.4
Credit facility	8.5	10.8
Other	1.2	0.9
Capitalized interest	(0.6)	(1.3)
Interest income	(0.1)	(0.2)
Total	$ 17.2	$ 18.6

Six Months Ended June 30, 2008 Compared to Six Months Ended June 30, 2007

Gross Margin and Profit on Energy Trading Activities. Midstream gross margin was $195.4 million for the six months ended June 30, 2008 compared to $134.1 million for the six months ended June 30, 2007, an increase of $61.3 million, or 45.7%. This increase was primarily due to system expansion projects, increased throughput and a favorable processing environment for NGLs. Profit on energy trading activities decreased for the comparative period.

System expansion in the north Texas region and increased throughput on the NTP contributed $33.0 million of gross margin growth for the six months ended June 30, 2008 over the same period in 2007. The gathering systems in the region and NTP accounted for $21.4 million and $4.6 million of this increase, respectively. The processing facilities in the region contributed an additional $7.0 million of this gross margin increase. System expansion and volume increases on the LIG system contributed margin growth of $11.4 million during the first half of 2008 over the same period in 2007. Processing plants in Louisiana contributed margin growth of $10.8 million for the comparative six month period in 2007 due to higher NGL prices and increased volumes at the Gibson and Plaquemine plants and the Riverside fractionation facility. These gains were partially offset by volume declines at the Eunice and Pelican plants. The south Texas region had a margin increase of $4.9 million for the comparative six-month periods primarily due to growth on the Vanderbilt system. Crosstex Pipeline in east Texas contributed margin growth of $1.6 million due to increased volume. This was partially offset by volume declines on the Arkoma system in Oklahoma which led to a margin decrease of $0.7 million for the comparable periods.

Treating gross margin was $28.9 million for the six months ended June 30, 2008 compared to $28.0 million for the same period in 2007, an increase of $0.9 million, or 3.1%. There were approximately 190 treating and dew point control plants in service at June 30, 2008, which is a slight decrease from the 195 in service at June 30, 2007. However, gross margin from plant operations increased slightly due to larger plants in operation. Field services provided to producers contributed $0.7 million in gross margin growth between comparative six month periods.

Operating Expenses. Operating expenses were $81.5 million for the six months ended June 30, 2008 compared to $57.3 million for the six months ended June 30, 2007, an increase of $24.2 million, or 42.3%. Midstream operating expenses have increased primarily due to expansion and growth of our midstream assets in the NTP, NTG, north Louisiana and east Texas areas, and increased costs for chemicals, materials and supplies and fuel also contributed to the increase. Contractor services and labor costs increased by $8.2 million for the first half of 2008 over the same period in 2007. Compressor rentals and related costs increased by $5.0 million and chemicals, materials and supplies and fuel costs increased by $4.6 million. Ad valorem taxes increased by $0.9 million due to our growth. Treating operating expenses increased by $4.1 million for the six months ended June 30, 2008 compared to the same period in 2007. We experienced similar cost increases on chemicals, materials and supplies, and fuel in our treating operations contributing to a $1.5 million increase between periods. Labor costs increased by $1.2 million as a result of market adjustments for field service employees and additional headcount. Contractor services costs to support maintenance projects contributed the remaining increase in operating expenses of $1.4 million. Operating expenses included $0.9 million of stock-based compensation expense for the six months ended June 30, 2008 compared to $0.7 million of stock-based compensation expense for the six months ended June 30, 2007.

General and Administrative Expenses. General and administrative expenses were $32.8 million for the six months ended June 30, 2008 compared to $26.9 million for the six months ended June 30, 2007, an increase of $5.9 million, or 22.0%. The staff additions associated with the requirements of the NTP and the NTG assets and the expansion in north Louisiana accounted for $2.9 million in increased costs. General and administrative expenses included stock-based compensation expense of $5.4 million and $4.4 million for the six months ended June 30, 2008 and 2007, respectively. The $1.0 million increase in stock-based compensation primarily relates to restricted stock and unit grants and increased headcount between comparative periods. Other expenses, including audit, legal and other consulting fees, office rent, travel and training accounted for $2.0 million of the increase.

Gain on Sale of Property. The $1.7 million gain on sale of property for the six months ended June 30, 2008 represents disposition of various small Treating and Midstream assets. The $1.8 million gain on sale of property for the six months ended June 30, 2007 consisted of the disposition of unused catalyst material for $1.0 million and the sale of a treating plant for $0.9 million, partially offset by losses on disposition of other treating equipment.

Gain/Loss on Derivatives. We had a gain on derivatives of $9.7 million for the six months ended June 30, 2008 compared to a gain of $4.5 million for the six months ended June 30, 2007. The derivative transaction types contributing to the net gain are as follows:

	Six Months Ended June 30,			
	2008		2007	
(Gain)/Loss on Derivatives	Total	Realized	Total	Realized
	(In million)			
Basic swaps	$ (4.7)	$ (3.6)	$ (5.2)	$ (2.7)
Interest rate swaps	(4.1)	2.0	(0.5)	—
Third-party on system swaps	(1.4)	(1.5)	—	—
Processing margin hedges	—	—	0.7	0.2
Puts	—	—	0.8	—
Other	0.5	—	(0.3)	—
	$ (9.7)		$ (4.5)	

Depreciation and Amortization. Depreciation and amortization expenses were $65.2 million for the six months ended June 30, 2008 compared to $50.5 million for the six months ended June 30, 2007, an increase of $14.7 million, or 29.2%. Midstream depreciation and amortization expense increased $13.3 million primarily due to the north Texas and the north Louisiana expansions. Software additions and depreciation acceleration of Dallas office leasehold improvements accounted for an increase between periods of $1.2 million.

Interest Expense. Interest expense was $37.3 million for the six months ended June 30, 2008 compared to $35.9 million for the six months ended June 30, 2007, an increase of $1.4 million, or 3.8%. The increase relates primarily to a decrease in capitalized interest. Net interest expense consists of the following (in millions):

	Six Months Ended June 30,	
	2008	2007
Senior notes	$ 16.4	$ 16.8
Credit facility	20.8	20.7
Other	2.2	1.9
Capitalized interest	(1.7)	(3.1)
Realized interest rate swap gains	(0.2)	—
Interest income	(0.2)	(0.4)
Total	$ 37.3	$ 35.9

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.

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, 2007.

Liquidity and Capital Resources

Cash Flows. Net cash provided by operating activities was $86.6 million for the six months ended June 30, 2008 compared to $48.6 million for the six months ended June 30, 2007. 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,	
	2008	2007
Income before non-cash income and expenses	$ 90.8	$ 52.5
Changes in working capital	$ (4.2)	$ (3.9)

The primary reason for the increased income before non-cash income and expenses of $38.3 million from 2007 to 2008 was increased operating income from our expansions in north Texas and north Louisiana during 2007 and 2008. 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, 2007 and 2008 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 $147.5 million and $227.0 million for the six months ended June 30, 2008 and 2007, respectively. Our primary investing activities were capital expenditures for internal growth, net of accrued amounts, as follows (in millions):

	Six Months Ended June 30,	
	2008	2007
Growth capital expenditures	$ 143.7	$ 226.3
Maintenance capital expenditures	7.6	3.6
Total	$ 151.3	$ 229.9

Net cash invested in Midstream assets was $124.9 million for the first six months of 2008 down from $213.9 million for 2007. Midstream spending declined in the six month period from 2007 to 2008 because the north Louisiana project was in progress and is reflected in the midstream capital expenditures for the first half of 2007. Net cash invested in Treating assets was $23.0 million for the first six months of 2008 and $13.0 million for 2007. Net cash invested in other corporate assets was $3.4 million for the first six months of 2008 and $3.0 million for 2007.

Cash flows from investing activities for the six months ended June 30, 2008 and 2007 also include proceeds from property sales of $3.8 million and $2.8 million, respectively. These sales primarily related to sales of various small Midstream and Treating assets.

Cash Flows from Financing Activities. Net cash provided by financing activities was $67.8 million and $177.9 million for the six months ended June 30, 2008 and 2007, 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 2008 and 2007 as follows (in millions):

	Six Months Ended June 30,	
	2008	2007
Net borrowings under bank credit facility	$ 36.0	$ 152.0
Senior note repayments	(4.7)	(4.7)
Net borrowings under capital lease obligations	11.9	—
Senior subordinated unit offerings(1)	—	102.6
Common unit offerings(1)	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 represent our primary use of cash in financing activities. 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 were as follows (in millions):

	Six Months Ended June 30,	
	2008	2007
Common units	$ 42.9	$ 23.7
Subordinated units	2.8	6.5
General partner	20.5	11.8
Total	$ 66.2	$ 42.0

In order to reduce our interest costs, we do not borrow money to fund outstanding checks until they are presented to the bank. Fluctuations in drafts payable are caused by timing of disbursements, cash receipts and draws on our revolving credit facility. We borrow money under our $1.185 billion credit facility to fund checks as they are presented. As of June 30, 2008, we had approximately $245.2 million of available borrowing capacity under this facility. Changes in drafts payable for the six months ended 2008 and 2007 were as follows (in millions):

	Six Months Ended June 30,	
	2008	2007
Decrease in drafts payable	$ 10.5	$ 30.3

Working Capital Deficit. We had a working capital deficit of $39.1 million as of June 30, 2008, primarily due to drafts payable of $18.4 million and accrued liabilities of $44.2 million, including $12.6 million attributable to accrued property development costs. As discussed under "Cash Flows" above, in order to reduce our interest costs we do not borrow money to fund outstanding checks until they are presented to our bank. We borrow money under our $1.185 billion bank credit facility to fund checks as they are presented. As of June 30, 2008, we had $245.2 million of available borrowing capacity under this facility.

Potential Shutdown of Blue Water Plant in Third Quarter of 2008. We own a 59.27% interest in the Blue Water gas processing plant located near Crowley, Louisiana and we also operate this plant. The Blue Water facility is connected to continental shelf and deepwater production volumes through the Blue Water pipeline system which is owned by Tennessee Gas Pipeline (TGP). During 2008, TGP sought and received approval from the Federal Energy Regulatory Commission, or FERC, to acquire Columbia Gulf Transmission's ownership share in the Blue Water pipeline. TGP intends to reverse the flow of the gas on the pipeline by September 2008 thereby removing access to all the gas processed at our Blue Water plant from the Blue Water offshore system. We are continuing to evaluate alternative sources of new gas which may include moving gas from our LIG system over to Blue Water or relocating the Blue Water plant to support our LIG system. We may decide to shut down the Blue Water plant temporarily but will continue to work on developing new supply sources for the plant. The Blue Water plant contributed gross margin of $1.5 million and $2.5 million and incurred operating expenses of $0.4 million and $0.7 million for the three and six months ended June 30, 2008, respectively. The net book value of the Blue Water plant was $29.1 million as of June 30, 2008.

Off-Balance Sheet Arrangements. We had no off-balance sheet arrangements as of June 30, 2008.

Capital Requirements of the Partnership. Given our objective of growth through acquisitions and large capital expansions, we anticipate that we will continue to invest significant amounts of capital to grow and to build and acquire assets. We actively consider a variety of assets for potential development and acquisitions.

We believe that cash generated from operations will be sufficient to meet our present quarterly distribution level of $0.63 per quarter and to fund a portion of our anticipated capital expenditures through June 30, 2009. We have approximately $196.0 million of planned spending on growth projects for the second half of the year, much of which could be deferred depending on our view of market conditions. We expect to fund the remaining capital expenditures from the proceeds of borrowings under our bank credit facility discussed below, and from other debt and equity sources. Our ability to pay distributions to our unit holders and to fund planned capital expenditures and to make acquisitions will depend upon our future operating performance, which will be affected by prevailing economic conditions in our industry and financial, business and other factors, some of which are beyond our control.

We were in compliance with all debt covenants as of June 30, 2008 and expect to be in compliance with debt covenants for the next twelve months.

Total Contractual Cash Obligations. A summary of our total contractual cash obligations as of June 30, 2008, is as follows:

	Payments Due by Period						
	Total	2008	2009	2010	2011	2012	Thereafter
				(In millions)			
Long-term debt	$ 1,254.4	$ 4.7	$ 9.4	$ 20.3	$ 802.0	$ 93.0	$ 325.0
Interest payable on fixed long-term debt obligations	179.9	16.3	32.1	31.0	29.8	26.3	44.4
Capital lease obligations	19.0	0.9	1.8	1.8	1.8	1.8	10.9
Operating leases	104.0	13.3	25.0	21.8	20.6	16.5	6.8
Unconditional purchase obligations	6.2	6.2	—	—	—	—	—
Total contractual obligations	$ 1,563.5	$ 41.4	$ 68.3	$ 74.9	$ 854.2	$ 137.6	$ 387.1

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

The unconditional purchase obligations for 2008 relate to purchase commitments for equipment. We have also committed to contract for 150,000 MMBtu/d of firm transportation capacity on the Gulf Crossing Pipeline that is expected to be in service in the first quarter of 2009. Under the transportation commitment agreement with Boardwalk Pipeline Partners, L.P., we will be obligated to issue a $42.0 million letter of credit if demanded by Boardwalk four months prior to commencement of operation of this new pipeline. We intend to eliminate all or a portion of our firm transportation capacity risk prior to commencement of the operation of the pipeline. This commitment is not reflected in the summary above.

Indebtedness

As of June 30, 2008 and December 31, 2007, long-term debt consisted of the following (in thousands):

	June 30, 2008	December 31, 2007
Bank credit facility, interest based on Prime and/or LIBOR plus an applicable margin, interest rates (per the facility) at June 30, 2008 and December 31, 2007 were 5.51% and 6.71%, respectively	$ 770,000	$ 734,000
Senior secured notes, weighted average interest rate at June 30, 2008 and December 31, 2007 was 6.75%	484,412	489,118
	1,254,412	1,223,118
Less current portion	(9,412)	(9,412)
Debt classified as long-term	$ 1,245,000	$ 1,213,706

Credit Facility. As of June 30, 2008, we had a bank credit facility with a borrowing capacity of $1.185 billion that matures in June 2011. As of June 30, 2008, $939.8 million was outstanding under the bank credit facility, including $169.8 million of letters of credit, leaving approximately $245.2 million available for future borrowing. The bank credit facility is guaranteed by certain of our subsidiaries.

Recent Accounting Pronouncements

In May 2008, the FASB issued Staff Position FSP EITF 03-6-1 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. Upon adoption, we will consider restricted units with nonforfeitable distribution rights in the calculation of earnings per unit and will adjust all prior reporting periods retrospectively to conform to the requirements.

In September 2006, the Financial Accounting Standards Board (FASB) issued SFAS No. 157, *"Fair Value Measurements"* (SFAS 157). SFAS 157 defines and introduces a framework for measuring fair value and expands required disclosure about fair value measurements of assets and liabilities. SFAS 157 for financial assets and liabilities is effective for fiscal years beginning after November 15, 2007, and we have adopted the standard for those assets and liabilities as of January 1, 2008 and the impact of adoption was not significant.

In February 2007, the FASB issued SFAS No. 159, *"Fair Value Option for Financial Assets and Financial Liabilities-Including an amendment to FASB Statement No. 115"* (SFAS 159). SFAS 159 permits entities to choose to measure many financial assets and financial liabilities at fair value. Changes in the fair value on items for which the fair value option has been elected are recognized in earnings each reporting period. SFAS 159 also establishes presentation and disclosure requirements designed to draw comparisons between the different measurement attributes elected for similar types of assets and liabilities. SFAS 159 was adopted effective January 1, 2008 and did not have a material impact on our financial statements.

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 will require 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. The statement applies to the accounting for noncontrolling interests and transactions with noncontrolling interest holders in consolidated financial statements. SFAS 160 is effective for periods beginning on or after December 15, 2008 and will be applied prospectively to all noncontrolling interests, including any that arose before the effective date except that comparative period information must be recast to classify noncontrolling interests in equity, attribute net income and other comprehensive income to noncontrolling interests, and provide other disclosures required by SFAS 160.

In March of 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. The principal impact to us will be to require expanded disclosure regarding derivative instruments.

Disclosure Regarding Forward-Looking Statements

This Quarterly Report on Form 10-Q includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended 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, 2007, 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, 2008, our bank credit facility had outstanding borrowings of $770.0 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 covering $100.0 million of the variable rate debt for a period of one year at an interest rate of 2.83%. As of June 30, 2008, the fair value of these interest rate swaps was reflected as a liability of $9.7 million ($7.2 million in net current liabilities and $2.5 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 $11.4 million. Considering the interest rate swaps and the amount outstanding on our bank credit facility as of June 30, 2008, we estimate that a 1% increase or decrease in the interest rate would change our annual interest expense by approximately $2.2 million for period when the entire portion of the $550.0 million of interest rate swaps are outstanding and $7.7 million for annual periods after 2011 when all the interest rate swaps lapse.

At June 30, 2008, we had total fixed rate debt obligations of $484.4 million, consisting of our senior secured notes with a weighted average interest rate of 6.75%. The fair value of these fixed rate obligations was approximately $482.0 million as of June 30, 2008. 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) by $22.3 million based on the debt obligations as of June 30, 2008.

Commodity Price Risk

Approximately 4.4% of the natural gas we market is purchased at a percentage of the relevant natural gas index price, as opposed to a fixed discount to that price. 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.

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 gas bought and sold on the same basis. However, it is normal to experience fluctuations in the volumes of 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.

We have commodity price risk associated with our processed volumes of natural gas. 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 control our risk on our current keep-whole contracts primarily through our ability to bypass processing when it is not profitable for us, or by contracts that revert to a minimum fee.

2. *Percent of proceeds 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 proceeds contracts, but 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.

We have hedges in place covering liquids volumes we expect to receive under percent of proceeds contracts. We currently have no hedges in place covering liquids volumes related to our processing margin contracts. The following table sets forth certain information regarding our NGL swaps outstanding at June 30, 2008. 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/Amount	We Pay	We Receive	Fair Value Asset/(Liability)
July 2008-December 2009	Ethane	222 (MBbls)	Index	$0.64 - $0.8575 ($/gallon)	$ (3,212)
July 2008-December 2009	Propane	232 (MBbls)	Index	$1.057 - $1.493 ($/gallon)	(5,067)
July 2008-December 2009	Iso Butane	60 (MBbls)	Index	$1.295 - $1.826 ($/gallon)	(1,604)
July 2008-December 2009	Normal Butane	82 (MBbls)	Index	$1.2775 - $1.7965 ($/gallon)	(2,202)
July 2008-December 2009	Natural Gasoline	170 (MBbls)	Index	$1.5725 - $2.19 ($/gallon)	(7,240)
					$ (19,325)

We have hedged our expected exposure to declines in prices for natural gas and NGL volumes produced for our account in the approximate percentages set forth below:

	2008	2009
Natural gas	88%	34%
NGLs	50%	29%

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 NYMEX futures or 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, 2008, outstanding natural gas swap agreements, NGL swap agreements, swing swap agreements, storage swap agreements and other derivative instruments were a net fair value liability of $23.5 million. The aggregate effect of a hypothetical 10% increase in gas and NGL prices would result in an increase of approximately $9.1 million in the net fair value liability of these contracts as of June 30, 2008.

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, 2008 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, 2008 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, 2008 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, 2007.

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
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).
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	—	Common Unit Purchase Agreement, dated as of April 8, 2008, by and among Crosstex Energy, L.P. and each of the Purchasers set forth on Schedule A thereto (incorporated by reference to Exhibit 10.1 to our Form 8-K dated April 9, 2008, filed on April 9, 2008).
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 Section 13 or 15(d) 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 8, 2008

EXHIBIT INDEX

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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 the 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 8, 2008

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 the 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 8, 2008

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, 2008 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 8, 2008

/s/ WILLIAM W. DAVIS

William W. Davis
Chief Financial Officer

August 8, 2008

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.