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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 March 31, 2003**

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, SUITE 600
DALLAS, TEXAS 75201
(Address of principal executive offices)
(Zip Code)

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

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

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

The number of the Registrants Common Units outstanding at May 12, 2003 was 2,633,000 common units and 4,667,000 subordinated units.

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CROSSTEX ENERGY, L.P.
PART I—FINANCIAL INFORMATION

Item 1. *Financial Statements*

CROSSTEX ENERGY, L.P.
(Successor to Crosstex Energy Services, Ltd.)
Consolidated Balance Sheets
March 31, 2003 and December 31, 2002
(In thousands)

	March 31, 2003	December 31, 2002
Assets		
Current assets:		
Cash and cash equivalents	$ 164	$ 1,308
Accounts receivable:		
Trade	191,686	104,802
Imbalances	99	79
Related party	540	—
Other	577	637
Assets from risk management activities	3,082	2,947
Prepaid expenses and other	2,695	1,225
Total current assets	198,843	110,998
Property and equipment:		
Transmission assets	51,285	50,391
Gathering systems	23,136	22,624
Gas plants	41,718	39,475
Other property and equipment	3,044	2,754
Construction in process	7,566	6,935
Total property and equipment	126,749	122,179
Accumulated depreciation	(14,414)	(12,231)
Total property and equipment, net	112,335	109,948
Assets from risk management activities	48	155
Intangible assets, net	5,132	5,340
Goodwill, net	4,873	4,873
Investment in limited partnerships	442	346
Other assets, net	882	778
Total assets	$ 322,555	$ 232,438
Liabilities and Partners' Equity		
Current liabilities:		
Accounts payable and accrued gas purchases	$ 199,866	$ 110,793
Accrued imbalances payable	239	149
Liabilities from risk management activities	5,561	4,006
Current portion of long-term debt	50	50
Other current liabilities	4,448	4,672
Total current liabilities	210,164	119,670
Long-term debt	20,750	22,500
Liabilities from risk management activities	225	271
Liability from interest rate swap	285	181
Partners' equity:		
Common unitholders (2,633 units issued and outstanding)	58,854	58,147
Subordinated unitholders (4,667 units issued and outstanding)	33,919	31,829
General partner interest (2% interest with 149 equivalent units outstanding)	1,083	1,016
Other comprehensive income (loss)	(2,725)	(1,176)
Total partners' equity	91,131	89,816
Total liabilities and partners' equity	$ 322,555	$ 232,438

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.
(Successor to Crosstex Energy Services, Ltd.)
Consolidated Statements of Operations
(In thousands)

	Three Months Ended March 31,	
	2003	2002
Revenues:		
Midstream	$ 245,315	$ 77,808

Treating	5,255	3,185
Total revenues	250,570	80,993
Operating costs and expenses:		
Midstream purchased gas	237,408	72,759
Treating purchased gas	2,416	1,113
Operating expenses	3,210	2,440
General and administrative	1,500	1,934
Stock based compensation	2,504	—
Impairments	—	3,150
(Profit) loss on energy trading contracts	(107)	(2,775)
Depreciation and amortization	2,435	1,909
Total operating costs and expenses	249,366	80,530
Operating income (loss)	1,204	463
Other income (expense):		
Interest expense, net	(410)	(680)
Other income	38	(35)
Total other income (expense)	(372)	(715)
Net income (loss)	$ 832	$ (252)
General Partner Share of Net Income	$ 17	
Limited Partners Share of Net Income	$ 815	
Net income per limited partners' unit:		
Basic and diluted	$ .11	
Weighted average limited partners' units outstanding		
Basic	7,300	
Diluted	7,340	

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.
(Successor to Crosstex Energy Services, Ltd.)
Consolidated Statements of Changes in Partners' Equity
Three months ended March 31, 2003
(In thousands)

	Crosstex Energy L.P.				
	Common Units	Subordinated Units	General Partner Interest	Other Comprehensive Income	Total
Balance, December 31, 2002	$ 58,147	$ 31,829	$ 1,016	$ (1,176)	$ 89,816
Offering Costs	(472)	—	—	—	(472)
Stock-based compensation	885	1,569	50	—	2,504
Net income	294	521	17	—	832
Hedging gains or losses reclassified to earnings				(384)	(384)
Adjustment in fair value of derivatives				(1,165)	(1,165)
	$ 58,854	$ 33,919	$ 1,083	$ (2,725)	$ 91,131

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.
(Successor to Crosstex Energy Services, Ltd.)

Consolidated Statements of Comprehensive Income
(In thousands)

	Three Months Ended March 31, 2003	Three Months Ended March 31, 2002
Net income (loss)	$ 832	$ (252)
Hedging gains or losses reclassified to earnings	(384)	(65)
Adjustment in fair value of derivatives	(1,165)	(333)
Comprehensive (loss)	$ (717)	$ (650)

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.
(Successor to Crosstex Energy Services, Ltd.)
Consolidated Statements of Cash Flows
(In thousands)

	Three Months Ended March 31, 2003	Three Months Ended March 31, 2002
Cash flows from operating activities:		
Net income (loss)	$ 832	$ (252)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation and amortization	2,435	1,909
Impairments	—	3,150
Income (loss) on investment in affiliated partnerships	4	(21)
Noncash stock-based compensation	2,504	—
Changes in assets and liabilities:		
Accounts receivable	(87,386)	7,899
Prepaid expenses	(1,470)	32
Accounts payable, accrued gas purchases, and other accrued liabilities	89,163	1,660
Risk management activities	36	(4,357)
Other	(328)	(27)
Net cash provided by operating activities	5,790	9,993
Cash flows from investing activities:		
Additions to property and equipment	(4,614)	(3,570)
Investment in affiliated partnerships	(100)	33
Net cash used in investing activities	(4,714)	(3,537)
Cash flows from financing activities:		
Proceeds from bank borrowings	44,100	46,250
Payments on bank borrowings	(45,850)	(51,750)
Payments for offering costs	(470)	—
Net cash used in financing activities	(2,220)	(5,500)
Net increase (decrease) in cash and cash equivalents	(1,144)	956
Cash and cash equivalents, beginning of period	1,308	352
Cash and cash equivalents, end of period	$ 164	$ 1,308
Cash paid for interest	$ 374	$ 447
Noncash transactions—stock based compensation	2,504	—

See accompanying notes to consolidated financial statements.

Crosstex Energy, L.P.
(Successor to Crosstex Energy Services, Ltd.)
Notes to Consolidated Financial Statements
March 31, 2003
(Unaudited)

1) General

Crosstex Energy, L.P. ("Partnership") is a natural gas midstream company. We have two industry segments, Midstream and Treating, with a geographic focus along the Texas Gulf Coast. Our Midstream division focuses on the gathering, processing, transmission and marketing of natural gas, as well as providing certain producer services, while our Treating division focuses on the removal of carbon dioxide and hydrogen sulfide from natural gas to meet pipeline quality specifications.

The accompanying 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 consolidated financial statements should be read in conjunction with the financial statements and notes thereto included in our annual report or Form 10-K for the year ended December 31, 2002.

(a) Initial Public Offering

On December 17, 2002, the Partnership completed an initial public offering of common units representing limited partner interests in the Partnership. Prior to its initial public offering, the Partnership was an indirect wholly owned subsidiary of Crosstex Energy Holdings Inc. (Crosstex Holdings). Crosstex Holdings conveyed to the Partnership its indirect wholly owned ownership interest in Crosstex Energy Services, Ltd. (CES) in exchange for (i) a 2% general partner interest (including certain Incentive Distribution Rights) in the Partnership, (ii) 333,000 common units and (iii) 4,667,000 subordinated units of the Partnership. Prior to the conveyance of CES to the Partnership, CES distributed certain assets to Crosstex Holdings including (i) the Jonesville and Clarkson gas plants, (ii) the Enron receivable and related derivative positions, and (iii) the right to receive a cash distribution of $2.5 million.

CES constitutes the Partnership's predecessor. The transfer of ownership interests in CES to the Partnership represented a reorganization of entities under common control and was recorded at historical cost. Accordingly, the accompanying financial statements include the historical results of operations of CES prior to transfer to the Partnership.

(b) Employee Incentive Plans

Pro Forma Income (loss) Per Share

Had compensation cost for the Partnership been determined based on the fair value at the grant date for awards in accordance with SFAS No. 123*Accounting for Stock Based Compensation*, the Partnership's net income (loss) would have been as follows:

	Three Months Ended March 31, 2003	Three Months Ended March 31, 2002
Net income (loss), as reported	$ 832	$ (3,918)
Add: Stock-based employee compensation expense included in reported net income	2,504	—
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards	2,618	65
Pro forma net income	$ 718	$ (3,983)

Net income per limited partner unit, as reported	
Basic	$ .11
Diluted	.11
Pro forma income per limited partner unit	
Basic	$ .10
Diluted	.10

The fair value of each option is estimated on the date of grant using the Black Scholes option-pricing model with the following weighted average assumptions used for grants in the three months ended March 31, 2003:

	Crosstex Energy, L.P. Three Months Ended March 31, 2003
Options granted	140,000
Dividend yield	10%
Expected volatility	24%
Risk free interest rate	2.15%
Expected life	3 years
Contractual life	10
Weighted average of fair value of options granted	$ 1.23

Modification of Options

Crosstex Holdings modified certain outstanding options in the first quarter of 2003, which allows the option holders to elect to be paid in cash for the modified options based on the fair value of the options. The total number of Crosstex Holdings options, which have been modified is approximately 242,000. These modified options have been accounted for using variable accounting as of the option modification date. Crosstex Holdings is responsible for paying the intrinsic value of the options for the holders who elect to cash out their options. Beginning in the first quarter of 2003, the Partnership recognizes stock compensation expense based on the estimated fair value at period end of the options modified. The Partnership recognized stock-based compensation expense of approximately $2.5 million for the three months ended March 31, 2003.

(c) Earnings per unit and anti-dilutive computations

Basic earnings per unit was computed by dividing net income, by the weighted average number of limited partner units outstanding for the period January 1, 2003 through March 31, 2003. The computation of diluted earnings per unit further assumes the dilutive effect of unit options.

The following are the share amounts used to compute the basic and diluted earnings per limited partner unit for the period January 1, 2003 through March 31, 2003 (in thousands, except per-unit amounts):

	January 1, 2003-March 31, 2003
Basic earnings per unit:	
Weighted average limited partner units outstanding	7,300
Dilutive earnings per unit:	
Weighted average limited partner units outstanding	7,300
Dilutive effect of exercise of options outstanding	40
Dilutive units	7,340

All outstanding units were included in the computation of diluted earnings per unit.

(d) New Accounting Pronouncements

In June 2001, the FASB issued SFAS No. 143, *Accounting for Asset Retirement Obligations*. This statement establishes standards for accounting for obligations associated with the retirement of tangible long-lived assets. This standard was required to be adopted by the Partnership beginning on January 1, 2003. The Partnership does not presently have any significant asset retirement obligations, and accordingly, the adoption of SFAS No. 143 had no impact on our results of operations or financial condition.

In January 2003, the FASB issued FASB Interpretation (FIN) No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others*. FIN No. 45 requires an entity to recognize a liability for the obligations it has undertaken in issuing a guarantee. This liability would be recorded at the inception of a guarantee and would be measured at fair value. Certain guarantees are excluded from the measurement provisions of the Interpretation. The measurement provisions of this statement apply prospectively to guarantees issued or modified after December 31, 2002. The disclosure provisions of the statement apply to financial statements for periods ending after December 15, 2002. The adoption of the statement had no material effect on the Partnership's financial statements.

In January 2003, the FASB issued FASB Interpretation No. 46, *Consolidation of Variable Interest Entities, an interpretation of ARB No. 51*. FIN No. 46 requires an entity to consolidate a variable interest entity if it is designated as the primary beneficiary of that entity even if the entity does not have a majority of voting interests. A variable interest entity is generally defined as an entity where its equity is unable to finance its activities or where the owners of the entity lack the risk and rewards of ownership. The provisions of this statement apply at inception for any entity created after January 31, 2003. For an entity created before February 1, 2003, the provisions of this Interpretation must be applied at the beginning of the first interim or annual period beginning after June 15, 2003. The Partnership is not the primary beneficiary of any variable interest entities, and accordingly, the adoption of Fin No. 46 did not have an impact on its financial statements.

(3) Investment in Limited Partnerships

The Partnership owns a 7.86% weighted average interest as the general partner in the five gathering systems of Crosstex Pipeline Company (CPC), a 20.31% interest as a limited partner in CPC, and a 50% interest in J.O.B. J.V. The Partnership accounts for its investments under the equity method, as it exercises significant influence in operating decisions as a general partner. Under this method, the Partnership records its equity in net earnings of the affiliated partnerships as income in other income (expense) in the consolidated statement of operations, and distributions received from them are recorded as a reduction in the Partnership's investment in the affiliated partnership.

(4) Long-Term Debt

In December 2001, the Predecessor and Union Bank of California, N.A. (UBOC) amended its secured credit facility. Revolver A ($60 million) was available for general corporate purposes, including the acquisition and installation of property and equipment. Revolver B ($15 million) was available to finance letters of credit and certain working capital requirements.

In connection with the Partnership's initial public offering, the Partnership amended the secured credit facility to provide a $67.5 million credit facility consisting of:

- A senior secured revolving acquisition facility in the aggregate principal amount of $47.5 million; and
- A senior secured revolving working capital facility in the aggregate principal amount of $20 million.

The acquisition facility is used to finance the acquisition and development of gas gathering, treating, and processing facilities, as well as general partnership purposes. At March 31, 2003, $20.0 million was outstanding under the acquisition facility, leaving approximately $27.5 million available for future borrowings. The acquisition facility will convert into a term loan on April 30, 2004, and we will be required to make eleven quarterly payments equal to 5% of outstanding borrowings. The first such payment will be due in July 2004. The term loan will mature in April 2007, at which time it will terminate and all outstanding amounts shall be due and payable. Prior to April 30, 2004, amounts borrowed and repaid under the acquisition credit facility may be reborrowed.

The working capital facility is used for ongoing working capital needs, letters of credit, distributions and general partnership purposes, including future acquisitions and expansions. At March 31, 2003, $19.1 million of letters of credit were issued under the working capital facility, leaving approximately $0.9 million available for future issuances of letters of credit or cash borrowings. The aggregate amount of borrowings under the working capital facility is subject to a borrowing base requirement relating to the amount of our cash and eligible receivables (as defined in the credit agreement), and there is a $5.0 million sublimit for cash borrowings. This facility will mature in April 2004, at which time it will terminate and all outstanding amounts shall be due and payable. Amounts borrowed and repaid under the working capital facility may be reborrowed. We will be required to reduce all working capital borrowings to zero for a period of at least 15 consecutive days once a year.

Our obligations under the credit facility are secured by first priority liens on all of our material pipeline, gas gathering and processing assets, all material working capital assets and a pledge of all of our equity interests in certain of our subsidiaries. The credit agreement is guaranteed by certain of our subsidiaries. We may prepay all loans under the credit facility at any time without premium or penalty (other than customary LIBOR breakage costs.)

Indebtedness under the acquisition facility and the working capital facility bear interest at our option at the administrative agent's reference rate plus 0.125% to 1.375% or LIBOR plus 1.625% to 2.875%. The applicable margin varies quarterly based on our leverage ratio. The fees charged for letters of credit range from 1.50% to 2.00% per annum, plus a fronting fee of 0.125% per annum. We incur quarterly commitment fees based on the unused amount of the credit facilities.

The credit agreement prohibits us from declaring distributions to unitholders if any event of default, as defined in the credit agreement, exists or would result from the declaration of distributions. In addition, the credit agreement limits our operating partnership's ability to:

- Incur indebtedness;
- Grant or assume liens;
- Make certain investments;
- Sell, transfer, assign or convey assets, or engage in certain mergers or acquisitions;
- Make distributions; or
- Engage in transactions with affiliates.

The credit facility contains the following covenants requiring us to maintain:

- A maximum ratio of funded debt to consolidated EBITDA (each as defined in the credit facility), measured quarterly on a rolling four quarter basis, of 4.00 to 1 through June 30, 2003, declining to 3.75 to 1 beginning September 30, 2003, pro forma for any asset acquisitions;
- A minimum interest coverage ratio (as defined in the credit agreement), measured quarterly on a rolling four quarter basis equal to 3.50 to 1;
- Minimum current ratio (as defined in the credit agreement), measured quarterly of 1 to l; and
- A minimum tangible net worth (as defined in the credit agreement) of $55 million.

The Partnership was in compliance with all debt covenants at March 31, 2003 and December 31, 2002.

In June 2002, as part of the purchase price of Florida Gas Transmission Company (FGTC), the Partnership issued a note payable for $800,000 to FGTC that is payable in $50,000 annual increments starting June 2003 through June 2006 with a final payment of $600,000 due in June 2007. The note bears interest payable annually at LIBOR plus 1%.

As of March 31, 2003 and December 31, 2002, long-term debt consisted of the following (in thousands):

	March 31, 2003	December 31, 2002
Acquisition credit facility, interest based at prime plus 0.625%, interest rate at December 31, 2002 was 4.88%	$ —	$ 1,750
Acquisition credit facility, interest based on LIBOR plus 2.125%. Interest rate at March 31, 2003 was 3.449% and at December 31, 2002 was 3.95%	20,000	20,000
Note payable to Florida Gas Transmission Company	800	800
	$ 20,800	$ 22,550
Less current portion	50	50
Debt classified as long-term	$ 20,750	22,500

In October 2002, the Partnership entered into an interest rate swap covering a principal amount of $20 million for a period of two years. The Partnership is subject to interest rate risk on its acquisition credit facility. The interest rate swap reduces this risk by fixing the LIBOR rate, prior to credit margin, at 2.29%, on $20 million of related debt outstanding over the term of the swap agreement. The Partnership has accounted for this swap as a cash flow hedge of the variable interest payments related to the $20 million of the acquisition credit facility outstanding. Accordingly, unrealized gains or losses relating to the swap which are recorded in other comprehensive income will be reclassified from other comprehensive income to interest expense over the period hedged.

(5) Partners' Capital

Cash Distributions

The Partnership announced on April 17, 2003 that it will make its initial distribution on its common and subordinated units of $0.576 on May 15, 2003, payable to holders of record on April 30, 2003. The distribution consists of $0.076 covering the period from the closing of the Partnership's IPO through December 31, 2002, and $0.50 covering the first quarter of 2003.

(6) Risk Management and Financial Instruments

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.

Set forth below is the summarized notional amount and terms of all instruments held for price risk management purposes at March 31, 2003 and December 31, 2002 (all quantities are expressed in British Thermal Units, and all prices are expressed in the Houston Ship Channel Inside FERC (HSC IF), Natural Gas Pipeline IF (NGPL IF), Reliant East Inside FERC (Reliant IF), Texas Eastern South Texas Inside FERC (TET STx IF) or Texas Eastern East Texas Inside FERC (TET Etx IF) for natural gas). The remaining term of the contracts extend no later than April 2004, with no single contract longer than 16 months. The Company's counterparties to hedging contracts include Morgan Stanley, Tractebel, Williams and Sempra. Changes in the fair value of the Partnership's derivatives related to Producer Services gas marketing activities are recorded in earnings. 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.

March 31, 2003

Transaction type	Total volume	Pricing terms	Remaining term of contracts	Fair value
Natural gas swaps Cash flow hedge	(520,000)	3.285 vs. Reliant IF to 4.86 vs. Reliant IF	April 2003-March 2004	$ (665,860)
Natural gas swaps Cash flow hedge	2,547,000	3.415 vs. HSC IF to 6.10 vs HSC IF	April 2003-April 2004	(1,799,054)
Natural gas swaps Cash flow hedge	(300,000)	5.48 vs. NGPL IF to 5.51 vs NGPL IF	April-August 2003	76,890
Natural gas swaps Cash flow hedge	305,000	5.39 vs TET STx IF	June-September 2003	(51,788)
Marketing trading transaction swaps	(699,000)	3.10 vs. TET Etx IF to 3.14 vs. TET Etx IF	April 2003-April 2004	(1,461,566)
Marketing trading transaction swaps	(406,000)	3.85 vs. HSC IF to 6.755 vs. HSC IF	April-October 2003	(1,422,558)
Marketing trading transaction swaps	(30,000)	3.635 vs. Reliant IF	April 2003	(50,205)

December 31, 2002

Type transaction	Total volume	Pricing terms	Remaining term of contracts	Fair value
Natural gas swaps Cash flow hedge	(500,000)	3.285 vs. Reliant IF to 4.01 vs. Reliant IF	January 2003-April 2004	$ (421,800)
Natural gas swaps Cash flow hedge	(440,000)	3.415 vs. HSC IF to 4.99 vs HSC IF	January-September 2003	(573,320)
Marketing trading transaction swaps	(1,149,000)	3.10 vs. TET Etx IF to 3.14 vs. TET Etx IF	January 2003-April 2004	(1,593,421)
Marketing trading transaction swaps	(1,096,000)	3.21 vs. HSC IF to 5.16 vs. HSC IF	January-October 2003	(441,277)
Marketing trading transaction swaps	(180,000)	3.185 vs Reliant IF to 3.635 vs. Reliant IF	January-May 2003	(219,330)

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.

Assets and liabilities related to off-system energy trading contracts that are accounted for as energy trading contracts are included in assets and liabilities from risk management activities. Assets and liabilities related to off-system energy trading contracts were as follows:

	March 31, 2003	December 31, 2002
	(In thousands)	
Assets from risk management activities:		
Current	$ 2,673	$ 2,947
Long-term	48	155
Liabilities from risk management activities:		
Current	$ 2,869	$ 3,046
Long-term	68	236

The Partnership estimates the fair value of its off-system 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	Two to three years	Total fair value
March 31, 2003	$ (196)	(20)	—	(216)
December 31, 2002	$ (99)	(81)	—	(180)

(7) Transactions with Related Parties

General and Administrative Expense Cap

The Partnership has a $6 million annual ($1.5 million quarterly) General and Administrative cap in the first year of operation, per the partnership agreement. Crosstex Energy Holdings Inc. bears the cost of any excess General and Administrative expenses. During the quarter ended March 31, 2003, the Partnership had excess expenses of approximately $.5 million.

Crosstex Pipeline

The Partnership also had related-party transactions with Crosstex Pipeline Company (CPC) which are summarized below:

- During the quarters ended March 31, 2003 and 2002, the Partnership bought natural gas from CPC in the amount of approximately $1.2 million and $0.6 million and paid for transportation of approximately $13,809 and $4,952 respectively, to CPC.

- During the quarters ended March 31, 2003 and 2002, the Partnership received a management fee from CPC in the amount of approximately $31,362 each quarter.

- During the quarters ended March 31, 2003 and 2002, the Partnership received distributions from CPC in the amount of approximately $51,734 and $45,201 respectively.

Camden Resources, Inc.

The Partnership treats gas for, and purchases gas from, Camden Resources, Inc. (Camden). Camden is an affiliate of the Partnership by way of equity investments made by Yorktown in Camden. During the quarters ended March 31, 2003 and 2002, the Partnership purchased natural gas from Camden in the amount of approximately $2.7 million and $1.0 million, respectively, and received approximately $47,580 and $61,250 in treating fees from Camden.

(8) Commitments and Contingencies

Each member of senior management of the Partnership is a party to an employment contract with the general partner. The employment agreements provide each member of senior management 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.

The Partnership is involved in various other 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.

(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 Gulf Coast System, the Corpus Christi System, the Gregory gathering system located around the Corpus Christi area, the Arkoma system in Okalahoma and various other small systems. Also included in the Midstream division are the Partnership's Producer Services operations. The Treating division generates fees from its plants either through volume-based treating contracts or though fixed monthly payments. Included in the Treating division are four gathering systems that are connected to the treating plants.

The accounting polices of the operating segments are the same as those described in note 2 of the Notes to Consolidated Financial Statements for the year ended December 31, 2002. The Partnership evaluates the performance of its operating segments based on earnings before income taxes and accounting changes, and after an allocation of corporate expenses. Corporate expenses are allocated to the segments on a pro rata basis based on assets. Intersegment sales are at cost.

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

		Midstream	Treating	Totals
		(In thousands)		
Three months ended March 31, 2003:				
Sales to external customers	$	245,315	5,255	250,570
Intersegment sales		1,504	(1,504)	—
Interest expense		402	9	410
Depreciation and amortization		1,820	615	2,435
Segment profit (loss)		398	434	832
Segment assets		313,441	9,495	322,937
Capital expenditures		2,691	1,923	4,614
Three months ended March 31, 2002:				
Sales to external customers	$	77,808	3,185	80,993
Intersegment sales		1,317	(1,317)	—
Interest expense		550	130	680
Depreciation and amortization		1,242	667	1,909
Segment profit (loss)		2,486	(2,738)	(252)
Segment assets		132,085	31,276	163,361
Capital expenditures		2,862	708	3,570

(10) Subsequent Events

On May 2, 2003, we announced that we had executed an agreement for the acquisition of a package of assets from Duke Energy Field Services, L.P. for $66.4 million The assets to be acquired are:

- The AIM Pipeline System (previously known as Mississippi Fuels) AIM is a major gathering and transmission system that gathers wellhead production in south-central Mississippi and markets gas to industrial and power plant users Covering 15 counties, the system consists of 625 miles of 4" through 20" pipeline. Recent throughput on the system has averaged approximately 82 MMcfd.

- A 12.4 percent interest in the Seminole Gas Processing Plant operated by Amerada Hess. Located in Gaines County, Texas, the Seminole Plant provides CO_2 separation, NGL extraction, and sulfur recovery services for several major oil companies. The facility has dedicated long-term reserves from the Seminole San Andres Unit, with a stable dedicated utilization of the CO_2 made available for tertiary oil recovery. The plant is in the process of completing a capacity expansion from 150 MMcfd to 210 MMcfd.

- The Conroe Gas Plant and Gathering System, which is a cryogenic gas processing plant with 10 miles of gathering pipelines located within the Conroe Field Unit in Montgomery County, Texas. Recent throughput on the system has been about 30 MMcfd compared to a capacity of approximately 65 MMcfd.

- The Black Warrior Pipeline system, which consist of approximately 125 miles of 4" to 12" gathering systems in Alabama. The primary gas supply is from coalbed methane gas from the Black Warrior Basin, with recent average throughput of approximately 113,800 MMBtu per day.

- Two small systems, Aurora Centana and Cadeville in Louisiana.

The acquisition will be financed through an expansion and amendment of the Partnership's existing credit facility. In addition, Crosstex is in the process of placing fixed-rate term debt with an institutional lender.

The Partnership expects to close the acquisition by June 30, 2003.

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. For more detailed information regarding the basis of presentation for the following information, you should read the notes to the financial statements included in this report.

Overview

We are a Delaware limited partnership formed by Crosstex Energy Holdings Inc. on July 12, 2002 to acquire indirectly 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. Our Midstream division focuses on the gathering, processing, transmission and marketing of natural gas, as well as providing certain producer services, while our Treating division focuses on the removal of carbon dioxide and hydrogen sulfide from natural gas to meet pipeline quality specifications. For the three months ended March 31, 2003, 75% of our gross margin was generated in the Midstream division, with the balance in the Treating division, and approximately 78% of our gross margin was generated in the Texas Gulf Coast region.

Since the formation of our predecessor, we have grown significantly as a result of our construction and acquisition of gathering and transmission pipelines, treating and processing plants. From January 1, 2000 through March 31, 2003, we have invested approximately $119.7 million to develop or acquire new assets. The purchased assets were acquired from numerous sellers at different periods and were accounted for under the purchase method of accounting. Accordingly, the results of operations for such acquisitions are included in our financial statements only from the applicable date of the acquisition. As a consequence, the historical results of operations for the periods presented may not be comparable.

Our results of operations are determined primarily by the volumes of natural gas gathered, transported, purchased and sold through our pipeline systems, processed at our processing facilities or treated at our treating plants. We generate revenues from four primary sources:

- gathering and transporting natural gas on the pipeline systems we own;

- processing natural gas at our processing plants;

- providing producer services; and

- treating natural gas at our treating plants.

The bulk of our operating profits are derived from the margins we realize for gathering and transporting natural gas through our pipeline systems. Generally, we buy gas from a producer, plant tailgate, 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 based on the same index price at which the gas was purchased. We attempt to execute all purchases and sales substantially concurrently.

The company's principal Midstream assets are:

- The Gulf Coast system, consisting of approximately 500 miles of pipe located in south Texas;

- The CCNG Transmission system, consisting of approximately 300 miles of pipe located in south Texas;

- The Gregory gathering system, consisting of approximately 300 miles of pipe located in the Corpus Christi. Texas Bay area;

- The Vanderbilt system, consisting of approximately 200 miles of pipe located in south Texas;

- The Arkoma gathering system, consisting of approximately 100 miles of pipe located in eastern Oklahoma;

Set forth in the table below is the volume of the natural gas purchased and sold at a fixed discount or premium to the index price and at a percentage discount or premium to the index price for our principal gathering and transmission systems and for our producer services business for the three months ended March 31, 2003. 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.

	Quarter Ended March 31, 2003			
	Gas Purchased		Gas Sold	
Asset or Business	Fixed Amount to Index	Percentage of Index	Fixed Amount to Index	Percentage of Index
	(in billions of MMBtus)			

Gulf Coast system	8.0	0.5	8.5	—
CCNG transmission system	13.5	0.1	13.6	—
Gregory gathering system (1)	11.5	0.5	10.2	—
Vanderbilt system (1)	0.7	2.3	2.5	—
Arkoma gathering system	—	0.9	0.9	—
Producer services (2)	22.1	0.7	22.8	—

(1) Gas sold is less than gas purchased due to production of natural gas liquids.

(2) These volumes are not reflected in revenues or purchased gas cost, but are presented net as a component of profit (loss) on energy trading contracts in accordance with EITF 02-03.

In addition to the margins generated by the Gregory gathering system, we generate revenues at our Gregory processing plant under two types of arrangements:

- For the three months ended March 31, 2003, we purchased approximately 29% of the natural gas volumes on our Gregory system under contracts in which we were exposed to the risk of loss or gain in processing the natural gas. Under these contracts, we fractionate the NGLs into separate NGL products, which we then sell at prices based upon the market price for NGL products. All of the processed natural gas is delivered to a single customer at a price based on a fixed price relative to a monthly index. Since we extract Btu's from the gas stream in the form of the liquids or consume it as fuel during processing, we reduce the Btu content of the natural gas but seek to more than offset this by creating value from the separated NGL products. Accordingly, our margins under these arrangements can be negatively affected in periods where the value of natural gas is high relative to the value of NGLs.

- For the three months ended March 31, 2003, we purchased approximately 71% of the natural gas volumes on our Gregory system at a spot or market price less a discount that includes a fixed margin for gathering, processing and marketing the natural gas and NGLs at our Gregory processing plant with no risk of loss or gain in processing the natural gas. Under these contracts, the producer retains ownership of the fractionated NGLs, and accordingly bears the risk and retains the benefits associated with processing the natural gas. We anticipate purchasing increasing percentages of gas under fixed fee arrangements as opposed to contracts under which the processing economics are for our account.

In our producer services business we currently purchase for resale volumes of natural gas that do not move through our gathering, processing or transmission assets from over 80 independent producers. We engage in such activities on more than 30 interstate and intrastate pipelines with a major emphasis on Gulf Coast pipelines. We focus on supply aggregation transactions in which we either purchase and resell gas and thereby eliminate the need of the producer to engage in the marketing activities typically handled by in-house marketing or supply departments of larger companies, or act as agent for the producer.

We generate treating revenues under three arrangements:

- a volumetric fee based on the amount of gas treated, which accounted for approximately 67% of the operating income in our Treating division for the three months ended March 31, 2003;

- a fixed fee for operating the plant for a certain period, which accounted for approximately 26% of the operating income in our Treating division for the three months ended March 31, 2003; or

- a fee arrangement in which the producer operates the plant, which accounted for approximately 7% of the operating income in our Treating division for the three months ended March 31, 2003.

Typically, we incur minimal incremental operating or administrative overhead costs when gathering and transporting additional natural gas through our pipeline assets. Therefore, we recognize a substantial portion of incremental gathering and transportation revenues as operating income.

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.

Our general and administrative expenses are dictated by the terms of our partnership agreement and our omnibus agreement with Crosstex Energy Holdings Inc. Our general partner and its affiliates are reimbursed for expenses incurred on our behalf. These expenses include the costs of employee, officer and director compensation and benefits properly allocable to Crosstex Energy, L.P., and all other expenses necessary or appropriate to the conduct of the business of, and allocable to, Crosstex Energy, L.P. Our partnership agreement provides that our general partner determines the expenses that are allocable to Crosstex Energy, L.P. in any reasonable manner determined by our general partner in its sole discretion. For the 12 month period ending December 17, 2003, the amount which we will reimburse our general partner and its affiliates for costs incurred with respect to the general and administrative services performed on our behalf will not exceed $6.0 million. This reimbursement cap does not apply to the cost of any third-party legal, accounting or advisory services received, or the direct expenses of management incurred, in connection with acquisition or business development opportunities evaluated on our behalf.

Crosstex Energy Holdings, Inc. modified certain terms of certain outstanding options in the first quarter of 2003. These modifications will result in variable award accounting for the modified options. Based on the March 31, 2003 unit value of $24.25 per unit, total compensation expense was approximately $2.5 million, which has been recorded by Crosstex Energy, L.P. as non-cash stock based compensation expense in the first quarter of 2003. Compensation expense in future periods will be adjusted for changes in the unit market price.

Among the significant acquisitions that affect the comparability of the periods discussed in this report are the Vanderbilt system and the Hallmark lateral. We acquired the Vanderbilt system in December 2002 for a purchase price of $12 million. The Vanderbilt system consists of approximately 20 miles of gathering lines in the same approximate geographic area as the Gulf Coast system. At the time of its acquisition it was transporting approximately 32,000 MMBtu of gas per day. We acquired the Hallmark lateral in June 2002 for approximately $2.3 million. Construction work totaling $2.6 million was completed in November 2002, which permitted gas to begin moving to new markets in December 2002.

Commodity Price Risks

Our profitability has been and will continue to be affected by volatility in prevailing NGL product and natural gas prices. Changes in the prices of NGL products correlate closely with changes in the price of crude oil. NGL product and natural gas prices have been subject to significant volatility in recent years in response to changes in the supply and demand for NGL products and natural gas market uncertainty.

Profitability under our gas processing contracts is impacted by the margin between NGL sales prices and the cost of natural gas and may be negatively affected by decreases in NGL prices or increases in natural gas prices.

Changes in natural gas prices impact our profitability since the purchase price of a portion of the gas we buy (approximately 8.2% in the first quarter of 2003) is based on a percentage of a particular natural gas price index for a period, while the gas is resold at a fixed dollar relationship to the same index. Therefore, during periods of low gas prices, these contracts can be less profitable than during periods of higher gas prices. However, on most of the gas we buy and sell, margins are not affected by such changes because the gas is bought and sold at a fixed relationship to the relevant index. Therefore, while changes in the price of gas can have very large impacts on revenues and cost of revenues, on this portion of the gas, the changes are equal and offsetting. For the remaining three quarters of 2003, we currently have hedges in place for approximately 61% of the gas we anticipate we will purchase on a percentage of index price, at an average price of $4.0296 per MMBtu.

Gas prices can also affect our profitability indirectly by influencing drilling activity and related opportunities for gas gathering, treating, and processing.

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 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. Hedges to protect our processing margins are generally for a more limited time frame than is possible for hedges in natural gas, as the financial markets for NGLs are not as developed as the markets for natural gas. Such hedges generally involve taking a short position with regard to the relevant liquids and an offsetting long position in the required volume of natural gas.

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, as happened in the case of the Enron loss discussed above. 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 decreases in such prices.

We manage our price risk related to future physical purchase or sale commitments for our producer services activities by entering into either corresponding physical delivery contracts or financial instruments with an objective to balance our future commitments and significantly reduce our risk to the movement in natural gas prices. However, we are subject to counterparty risk for both the physical and financial contracts. We account for certain of our producer services natural gas marketing activities as energy trading contracts or derivatives. These energy-trading contracts are recorded at fair value with changes in fair value reported in earnings. Accordingly, any gain or loss associated with changes in the fair value of derivatives and physical delivery contracts relating to our producer services natural gas marketing activities are recognized in earnings as profit or loss on energy trading contracts immediately.

For each reporting period, we record the fair value of open energy trading contracts based on the difference between the quoted market price and the contract price. Accordingly, the change in fair value from the previous period is reported as profit or loss on energy trading contracts in the statement of operations. In addition, realized gains and losses from settled contracts are also recorded in profit or loss on energy trading contracts.

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 March 31,	
	2003	2002
	(in millions)	
Midstream revenues	$ 245.3	$ 77.8
Midstream purchased gas	237.4	72.7
Midstream gross margin	7.9	5.1
Treating revenues	5.2	3.2
Treating purchased gas	2.4	1.1
Treating gross margin	2.8	2.1
Total gross margin	$ 10.7	$ 7.2
Midstream Volumes (MMBtu/d):		
Gathering and transportation	498,643	369,260
Processing	93,855	85,593
Producer services	253,985	214,432
Treating Volumes (MMBtu/d)	87,561	91,581

Three Months Ended March 31, 2003 Compared to Three Months Ended March 31, 2002

Revenues. Midstream revenues were $245.3 million for the quarter ended March 31, 2003 compared to $77.8 million for the quarter ended March 31, 2002, an increase of $167.5 million, or 215%. The average NYMEX settlement price was $6.33 per MMBtu in the first quarter of 2003 compared to $2.34 in the first quarter of 2002, which increased revenues by $65.0 million. $49.9 million of revenue was generated by the Vanderbilt and Hallmark systems that were not in operation in the first quarter of 2002. Additional increases in revenue were generated at Gregory Gathering ($21.6 million) and Gregory Processing ($28.0 million) due to new volumes into the systems from producer drilling. $9.0 million additional revenue was generated at CCNG Transmission due to new markets adding volume to the system. These increases were offset by a decrease in revenue of $6.1 million at Gulf Coast and Arkoma due to a decrease in volume at these two systems.

Treating revenues were $5.2 million for the quarter ended March 31, 2003 compared to $3.2 million in the same period in 2002, an increase of $2.0 million, or 65%. Increases in the price of natural gas contributed $4.9 million of the increase, and $1.1 million of the increase was due to 17 new plants placed in service. This increase was partially offset by volume decreases at three plants which reduced revenue by $3.6 million and 7 plants were removed from service which reduced revenue by $0.4 million.

Purchased Gas Costs. Midstream purchased gas costs were $237.4 million for the quarter ended March 31, 2003 compared to $72.8 million for the quarter ended March 31, 2002, an increase of $164.6 million, or 226%. The increase was due to the increase in natural gas prices discussed above contributed $64.7 million to the increased costs. Additional costs of 47.9 million were generated by the Vanderbilt and Hallmark systems that were not in operation in the first quarter of 2002. Additional costs were generated at Gregory Gathering of $21.2 million and Gregory Processing ($27.5 million) due to new volumes into the systems from producer drilling. Additional costs of $8.9 million generated at CCNG Transmission due to additional volume to fulfill new market demands. This is offset by a decrease in purchased gas costs of $5.6 million at the Gulf Coast and Arkoma systems due to a decrease in volume at these two systems.

Treating purchased gas costs were $2.4 million in 2003 compared to $1.1 million in 2002, an increase of $1.3 million or 117%. The increase in natural gas prices caused a $4.9 million increase, offset by a decrease in treating volumes at three volume sensitive plants which resulted in a $3.6 million decline.

Operating Expenses. Operating expenses were $3.2 million for the quarter ended March 31, 2003, compared to $2.4 million for the quarter ended March 31, 2002, an increase of $0.8 million, or 32%. The increase was primarily due to the Vanderbilt system, Hallmark lateral, and new treating plants in service.

General and Administrative Expenses. General and administrative expenses were $1.5 million for the quarter ended March 31, 2003 compared to $1.9 million for the quarter ended March 31, 2002, a decrease of $0.4 million, or 21%. The decrease was due to the $6 million annual General and Administrative cap in the first year of partnership operation, per the partnership agreement. Had the cap not been in place, General and Administrative expenses would have been $2.0 million for the quarter ended March 31, 2003.

Stock-based compensation. Stock-based compensation was $2.5 million for the quarter ended March 31, 2003, compared to none in the first quarter of 2002. This stock-based compensation related to a modification in employee option agreements, which allowed the option holders to elect to be paid in cash for the modified options based on the fair value of those options.

Impairments. There was no impairment expense in the first quarter 2003 compared to $3.1 million in the first quarter of 2002. Intangible assets were booked associated with the contract values of certain treating plants and other assets in conjunction with the Yorktown investment in May 2000. Impairment charges in the first quarter of 2002 were associated with intangible contract values at two specific treating plants. These two plants are still working at the location where they were sited at the time of the Yorktown investment, but had experienced recent declines in cash flows.

(Profit) Loss on Energy Trading Contracts. The profit on energy trading contracts was $.1 million for the quarter ended March 31, 2003 compared to $2.8 million for the quarter ended March 31, 2002, a decrease of $2.7 million. Included in these amounts were realized margins on delivered volumes in the producer services "off-system" gas marketing operations of $0.5 million in 2003 and $0.3 million in 2002. In addition, gains of $2.5 million relating primarily to options bought and/or sold in the management of the company's Enron position were booked in 2002.

Depreciation and Amortization. Depreciation and amortization expense was $2.4 million for the quarter ended March 31, 2003 compared to $1.9 million for the quarter ended March 31, 2002, an increase of $0.5 million, or 28%. This is due to an increase in fixed assets of $32 million from March 31, 2002 to March 31, 2003.

Interest Expense. Interest expense was $0.4 million for the quarter ended March 31, 2003 compared to $0.7 million for the quarter ended March 31, 2002, a decrease of $0.3 million, or 40%. The decrease is due to a reduction in bank debt from the proceeds of the Initial Public Offering.

Net Income (Loss). Net income (loss) for the quarter ended March 31, 2003 was $0.8 million compared to ($0.3) million for the quarter ended March 31, 2002, an increase of $1.1 million. The key drivers of this increase were an increase in gross margin of $3.6 million, offset principally by a significant increase in stock based compensation of $2.5 million.

Critical Accounting Policies

The selection and application of accounting policies is an important process that has developed as our business activities have evolved and as the accounting rules have developed. Accounting rules generally do not involve a selection among alternatives, but involve an implementation and interpretation of existing rules, and the use of judgment to the specific set of circumstances existing in our business. Compliance with the rules necessarily involves reducing a number of very subjective judgments to a quantifiable accounting entry or valuation. We make every effort to properly comply with all applicable rules on or before their adoption, and we believe the proper implementation and consistent application of the accounting rules is critical. Our critical accounting policies are discussed below. For further details on our accounting policies and a discussion of new accounting pronouncements, see Note 2 of the Notes to Consolidated Financial Statements for the Year Ended December 31, 2002.

Revenue Recognition and Commodity Risk Management. We recognize revenue for sales or services at the time the natural gas or natural gas liquids are delivered or at the time the service is performed.

We engage in price risk management activities in order to minimize the risk from market fluctuations in the price of natural gas and natural gas liquids. We also manage our price risk related to future physical purchase or sale commitments by entering into either corresponding physical delivery contracts or financial instruments with an objective to balance our future commitments and significantly reduce our risk to the movement in natural gas prices.

Prior to January 1, 2001, financial instruments which qualified for hedge accounting were accounted for using the deferral method of accounting, whereby unrealized gains and losses were generally not recognized until the physical delivery required by the contracts was made.

Effective January 1, 2001, we adopted Statement of Financial Accounting Standards No. 133 ("SFAS No. 133"),*Accounting for Derivative Instruments and Hedging Activities*. In accordance with SFAS No. 133, all derivatives and hedging instruments are recognized as assets or liabilities at fair value. If a derivative qualifies for hedge accounting, changes in the fair value can be offset against the change in the fair value of the hedged item through earnings or recognized in other comprehensive income until such time as the hedged item is recognized in earnings.

We conduct "off-system" gas marketing operations as a service to producers on systems that we do not own. We refer to these activities as part of producer services. In some cases, we earn an agency fee from the producer for arranging the marketing of the producer's natural gas. In other cases, we purchase the natural gas from the producer and enter into a sales contract with another party to sell the natural gas. Where we take title to the natural gas, the purchase contract is recorded as cost of gas purchased and the sales contract is recorded as revenue upon delivery.

We manage our price risk related to future physical purchase or sale commitments for producer services activities by entering into either corresponding physical delivery contracts or financial instruments with an objective to balance our future commitments and significantly reduce our risk to the movement in natural gas prices. However, we are subject to counterparty risk for both the physical and financial contracts. Prior to October 26, 2002, we accounted for our producer services natural gas marketing activities as energy trading contracts in accordance with EITF 98-10, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities*. EITF 98-10 required energy-trading contracts to be recorded at fair value with changes in fair value reported in earnings. In October 2002, the EITF reached a consensus to rescind EITF No. 98-10. Accordingly, energy trading contracts entered into subsequent to October 25, 2002, should be accounted for under accrual accounting rather than mark-to-market accounting unless the contracts meet the requirements of a derivative under SFAS No. 133. Our energy trading contracts qualify as derivatives, and accordingly, we continue to use mark-to-market accounting for both physical and financial contracts of our producer services business. Accordingly, any gain or loss associated with changes in the fair value of derivatives and physical delivery contracts relating to our producer services natural gas marketing activities are recognized in earnings as profit or loss on energy trading contracts immediately.

For each reporting period, we record the fair value of open energy trading contracts based on the difference between the quoted market price and the contract price. Accordingly, the change in fair value from the previous period in addition to the realized gains or losses on settled contracts are reported as profit or loss on energy trading contracts in the statements of operations.

Impairment of Long-Lived Assets. In accordance with Statement of Financial Accounting Standards No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, we evaluate the long-lived assets, including related intangibles, of identifiable business activities for impairment when events or changes in circumstances indicate, in management's judgment, that the carrying value of such assets may not be recoverable. The determination of whether impairment has occurred is based on management's estimate of undiscounted future cash flows attributable to the assets as compared to the carrying value of the assets. If impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value for the assets and recording a provision for loss if the carrying value is greater than fair value.

When determining whether impairment of one of our long-lived assets has occurred, we must estimate the undiscounted cash flows attributable to the asset. Our estimate of cash flows is based on assumptions regarding the purchase and resale margins on natural gas, volume of gas available to the asset, markets available to the asset, operating expenses, and future natural gas prices and NGL product prices. The amount of availability of gas to an asset is sometimes based on assumptions regarding future drilling activity, which may be dependent in part on natural gas prices. Projections of gas volumes and future commodity prices are inherently subjective and contingent upon a number of variable factors, including but not limited to:

- changes in general economic conditions in regions in which our markets are located;
- the availability and prices of natural gas supply;
- our ability to negotiate favorable sales agreements;
- the risks that natural gas exploration and production activities will not occur or be successful;
- our dependence on certain significant customers, producers, and transporters of natural gas; and
- competition from other midstream companies, including major energy producers.

Any significant variance in any of the above assumptions or factors could materially affect our cash flows, which could require us to record an impairment of an asset.

Liquidity and Capital Resources

Cash Flows. Net cash provided by operating activities was $5.4 million and $10.0 million for the quarters ended March 31, 2003 and 2002, respectively. Net cash provided by operating activities in 2003 declined principally due to fund flows for working capital accounts ($6.0 million) and a decrease in profit on energy trading contracts ($2.3 million) due to the Enron-related positions that were outstanding in 2002. These decreases were offset by higher margins ($3.6 million).

Net cash used in investing activities was $4.7 million and $3.5 million for the quarters ended March 31, 2003 and 2002, respectively. Net cash used in investing activities during both periods were primarily related to internal growth projects. Net cash used in investing activities during each of the quarters ended March 31, 2003 and 2002 were primarily to fund the Gregory plant expansion, buying and refurbishing and installing treating plants, and other internal growth capital projects.

Net cash used in financing activities was $1.8 million and $5.5 million for the quarters ended March 31, 2003 and 2002, respectively. Financing activities primarily represented funding or refunding of the partnership's debt and working capital needs.

Capital Requirements. The natural gas gathering, transmission, treating and processing businesses are capital-intensive, requiring significant investment to maintain and upgrade existing operations. Our capital requirements have consisted primarily of, and we anticipate will continue to be:

- maintenance capital expenditures, which are capital expenditures made to replace partially or fully depreciated assets in order to maintain existing operating capacity of our assets and to extend their useful lives, or other capital expenditures which do not increase the partnership's cash flows; and
- growth capital expenditures such as those to acquire additional assets to grow our business, to expand and upgrade gathering systems, transmission capacity, processing plants or treating plants, and to construct or acquire new pipelines, processing plants or treating plants.

Given our objective of growth through acquisitions, we anticipate that we will continue to invest significant amounts of capital to grow and acquire assets. We actively consider a variety of assets for potential acquisitions. In addition, we are currently expanding the capacity of our Gregory processing plant by 65,000 Mcf/d at an estimated cost of approximately $7.0 million.

On May 2, 2003, we announced an agreement with Duke Energy Field Services, LP, in which we agreed to acquire certain assets from DEFS for approximately $66.4 million. We believe we will be able to fund this acquisition through an expansion and modification of our existing bank facility. In addition, we are in the process of placing fixed-rate term debt with an institutional lender to fund a portion of the requirements.

We believe that cash generated from operations will be sufficient to meet our minimum quarterly distributions and anticipated maintenance capital expenditures through December 31, 2003. We expect to fund our growth capital expenditures from cash provided by operations and, to the extent necessary, from the proceeds of borrowings under the revolving credit facility discussed below and the issuance of additional common units. We may not be able to issue additional units or may not be able to issue such units on favorable terms primarily as a result of market conditions for our securities. Our ability to pay distributions to our unitholders 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.

Description of Credit Facility

In connection with the closing of our initial public offering, we entered into a new $67.5 million credit facility, consisting of the following two facilities:

- a senior secured revolving acquisition facility in the aggregate principal amount of $47.5 million; and
- a senior secured revolving working capital facility in the aggregate principal amount of $20.0 million.

The acquisition facility is used to finance the acquisition and development of gas gathering, treating and processing facilities, as well as general partnership purposes. At March 31, 2003, we had $20.0 million outstanding under the acquisition facility, leaving approximately $27.5 million available for future borrowings. The acquisition facility will convert into a term loan on April 30, 2004, and we will be required to make eleven quarterly payments equal to five percent of the outstanding borrowings. The first such payment will be due in July 2004. The term loan will mature in April 2007, at which time it will terminate and all outstanding amounts shall be due and payable. Prior to April 30, 2004, amounts borrowed and repaid under the acquisition credit facility may be reborrowed.

The working capital facility is used for ongoing working capital needs, letters of credit, distributions and general partnership purposes, including future acquisitions and expansions. At March 31, 2003, we had $19.1 million of letters of credit issued under the working capital facility, leaving approximately $0.9 million available for future issuances of letters of credit or cash borrowings. The aggregate amount of borrowings under the working capital facility is subject to a borrowing base requirement relating to the amount of our cash and eligible receivables (as defined in the credit agreement), and there is a $5.0 million sublimit for cash borrowings. This facility will mature in April 2004, at which time it will terminate and all outstanding amounts shall be due and payable. Amounts borrowed and repaid under the working capital facility may be reborrowed. We are required to reduce all working capital borrowings to zero for a period of at least 15 consecutive days once each year.

Our obligations under the credit facility are secured by first priority liens on all of our material pipeline, gas gathering and processing assets, all material working capital assets and a pledge of all of our equity interests in certain of our subsidiaries. The credit facility is guaranteed by certain of our subsidiaries. We may prepay all loans under the bank credit facility at any time without premium or penalty (other than customary LIBOR breakage costs) but will incur a prepayment penalty for early repayment of the institutional facility.

Indebtedness under the acquisition facility and the working capital facility bear interest at our option at the administrative agent's reference rate plus 0.125% to 1.375% or LIBOR plus 1.625% to 2.875%. The applicable margin will vary quarterly based on our leverage ratio. The fees charged for letters of credit range from 1.50% to 2.00% per annum, plus a fronting fee of 0.125% per annum. At March 31, 2003, our interest rate was 3.449%. We will incur quarterly commitment fees based on the unused amount of the credit facilities.

In October 2002, the Partnership entered into an interest rate swap covering a principal amount of $20 million for a period of two years. The Partnership is subject to interest rate risk on its acquisition credit facility. The interest rate swap reduces this risk by fixing the LIBOR rate, prior to credit margin, at 2.29%, on $20 million of related debt outstanding over the term of the swap agreement. The Partnership has accounted for this swap as a cash flow hedge of the variable interest payments related to the $20 million of the acquisition credit facility outstanding. Accordingly, unrealized gains or losses relating to the swap which are recorded in other comprehensive income will be reclassified from other comprehensive income to interest expense over the period hedged.

The credit agreement prohibits us from declaring distributions to unitholders if any event of default, as defined in the credit agreement, exists or would result from the declaration of distributions. In addition, the credit facility contains various covenants limiting our operating partnership's ability to:

- incur indebtedness;
- grant or assume liens;
- make certain investments;
- sell, transfer, assign or convey assets, or engage in certain mergers or acquisitions;
- make distributions; or
- engage in transactions with affiliates.

The credit facility also contains covenants requiring us to maintain:

- a maximum ratio of total funded debt to consolidated EBITDA (each as defined in the credit facility), measured quarterly on a rolling four quarter basis, of 4.00 to 1 through June 30, 2003, declining to 3.75 to 1 beginning September 30, 2003, pro forma for any asset acquisitions;
- a minimum interest coverage ratio (as defined in the credit agreement), measured quarterly on a rolling four quarter basis, equal to 3.50 to 1;

- minimum current ratio (as defined in the credit agreement), measured quarterly, of 1 to 1; and
- a minimum tangible net worth (as defined in the credit agreement) of $55 million plus 50% of the net proceeds of any future equity offering.

Each of the following is an event of default under the credit facility:

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

The acquisition from DEFS will require a substantial modification and expansion of the company's credit facilities. In addition, we are in the process of placing fixed-rate term debt with an institutional lender. We expect many of the terms in the amended facilities to differ substantially from the terms discussed above.

Credit Risk

We are diligent in attempting to ensure that we issue credit to only credit-worthy customers. However, our purchase and resale of gas exposes us to significant credit risk, as the margin on any sale is generally a very small percentage of the total sale price. Therefore, a credit loss can be very large relative to our overall profitability.

Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the three months ended March 31, 2003 or 2002. Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy and may increase the cost to acquire or replace property, plant and equipment and may increase the costs of labor and supplies. To the extent permitted by competition, regulation and our existing agreements, we have and will continue to pass along increased costs to our customers in the form of higher fees.

Environmental

Our operations are subject to environmental laws and regulations adopted by various governmental authorities in the jurisdictions in which these operations are conducted. We believe we are in material compliance with all applicable laws and regulations.

Recent Accounting Pronouncements

In June 2001, the FASB issued SFAS No. 143, *Accounting for Asset Retirement Obligations*. This statement establishes standards for accounting for obligations associated with the retirement of tangible long-lived assets. This standard is required to be adopted by us beginning on January 1, 2003. We do not presently have any significant asset retirement obligations, and accordingly, the adoption of SFAS No. 143 did not have a significant impact on our results of operations or financial condition.

In January 2003, the FASB issued Interpretation (FIN) No. 45, *Guarantor's Accounting and Disclosure Requirement for Guarantees, including Indirect Guarantees of Indebtedness of Others*. FIN No. 45 requires an entity to recognize a liability for the obligations it has undertaken in issuing a guarantee. This liability would be recorded at the inception of a guarantee and would be measured at fair value. Certain guarantees are excluded from the measurement and disclosure provisions while certain other guarantees are excluded from the measurement provisions of the interpretation. The measurement provisions of this statement apply prospectively to guarantees issued or modified after December 31, 2002. The disclosure provisions of the statement apply to financial statements for periods ending after December 15, 2002. The adoption of the statement did not have a material effect on the Partnership's financial statements.

In January 2003, the FASB issued FASB Interpretation No. 46, *Consolidation of Variable Interest Entities*. FIN No. 46 requires an entity to consolidate a variable interest entity if it is designated as the primary beneficiary of that entity even if the entity does not have a majority of voting interests. A variable interest entity is generally defined as an entity where its equity is unable to finance its activities or where the owners of the entity lack the risk and rewards of ownership. The provisions of this statement apply at inception for any entity created after January 31, 2003. For an entity created before February 1, 2003, the provisions of this interpretation must be applied at the beginning of the first interim or annual period beginning after June 15, 2003. The Partnership is not the primary beneficiary of any variable interest entities, and accordingly, the adoption of FIN No. 46 did not have an impact on our financial statements.

Risk Factors Related to Our Business

Cash distributions are not guaranteed and may fluctuate with our performance and the establishment of financial reserves.

Because distributions on the common units are dependent on the amount of cash we generate, distributions may fluctuate based on our performances. We cannot guarantee that we will be able to pay the minimum quarterly distributions of $0.50 per common unit in each quarter. The actual amount of cash that is available to be distributed each quarter will depend upon numerous factors, some of which are beyond our control and the control of our general partner. Cash distributions are dependent primarily on cash flow, including cash flow from financial reserves and working capital borrowings, and not solely on profitability, which is affected by non-cash items. Therefore, cash distributions might be made during periods when we record losses and might not be made during periods when we record profits.

Potential future acquisitions and expansions, if any, may affect our business by substantially increasing the level of our indebtedness and contingent liabilities and increasing our risks of being unable to effectively integrate these new operations.

From time to time, we evaluate and acquire assets and businesses that we believe complement our existing assets and businesses. Acquisitions may require substantial capital or the incurrence of substantial indebtedness. If we consummate any future acquisitions, our capitalization and results of operations may change significantly and you will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources.

The success of our business strategy to increase and optimize throughput on our pipeline and gathering assets is dependent upon our securing additional supplies of natural gas.

Our operating results are dependent upon securing additional supplies of natural gas from increased production by natural gas production companies in the Texas Gulf Coast. The ability of producers to increase production is dependent on natural gas, the exploration and production budgets of the production companies, the depletion rate of existing reservoirs, the success of new wells drilled, environmental concerns, regulatory initiatives and other matters beyond our control. There can be no assurance that production of natural gas will rise to sufficient levels to maintain or increase the throughput on our pipeline and gathering assets.

Our operations are dependent upon demand for natural gas by industry and utilities in the Texas Gulf Coast. Any decrease in this demand could adversely affect our business.

We face intense competition in our gathering and marketing activities.

Our competitors include other natural gas pipelines and their marketing affiliates, and independent gatherers, brokers and marketers of widely varying sizes, financial resources and experience. Some of these competitors have capital resources many times greater than ours and control substantially greater supplies of natural gas.

We are exposed to the credit risk of our customers in the ordinary course of our gathering and marketing activities. In our gathering and marketing operations, we take title to the natural gas and resell the gas to our various market outlets, which include a variety of utility, refining, petrochemical, metals production and other industrial consumers, as well as to the pipeline companies. A significant failure to pay by one of our major customers would adversely affect our ability to maintain distributions.

Disclosure Regarding Forward-Looking Statements

Statements included in this report which are not historical facts (including any statements concerning plans and objectives of management for future operations or economic performance, or assumptions or forecasts related thereto), are forward-looking statements. These statements can be identified by the use of forward-looking terminology including "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.

These forward-looking statements are made based upon management's current plans, expectations, estimates, assumptions and beliefs concerning future events impacting us and therefore involve a number or risks and uncertainties. We caution that forward-looking statements are not guarantees and that actual results could differ materially from those expressed or implied in the forward-looking statements.

Because these forward-looking statements involve risks and uncertainties, actual results could differ materially from those expressed or implied by these forward-looking statements for a number of important reasons, including those discussed under "Risk Factors Related to Our Business," and elsewhere in this report.

You should read these statements carefully because they discuss our expectations about our future performance, contain projections of our future operating results or our future financial condition, or state other "forward-looking" information. You should be aware that the occurrence of any of the events described in "Risk Factors Related to Our Business" and elsewhere in this report could substantially harm our business, results of operations and financial condition and that upon the occurrence of any of these events, the trading price of our common units could decline.

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

See Item 2. "Management's Discussion and Analysis—Commodity Price Risks, Description of Credit Facility and Credit Risk".

Item 4. *Controls and Procedures*

An evaluation of the effectiveness of the design and operation of the Partnership's disclosure controls and procedures as of May 8, 2003 was carried out by the General Partner under the supervision and with the participation of the General Partner's management, including the Chief Executive Officer and Chief Financial Officer. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Partnership's disclosure controls and procedures have been designed and are being operated in a manner that provides reasonable assurance that the information required to be disclosed by the Partnership in reports filed under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. A controls system, no matter how well designed and operated, cannot provide absolute assurance that the objectives of the controls system are met, and no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within an entity have been detected. Subsequent to the date of the most recent evaluation of the Partnership's internal controls, there were no significant changes in the Partnership's internal controls or in other factors that could significantly affect the internal controls, including any corrective actions with regard to significant deficiencies and material weaknesses.

PART II—OTHER INFORMATION

Item 1. *Legal Proceedings*

We are not currently a party to any material litigation. Our operations are subject to a variety of risks and disputes normally incident to our business. As a result, at any given time we may be a defendant in various legal proceedings and litigation arising in the ordinary course of business. We maintain insurance policies with insurers in amounts and with coverage and deductibles as the managing general partner believes are reasonable and prudent. However, we cannot assure that this insurance will be adequate to protect us from all material expenses related to potential future claims for personal and property damage or that these levels of insurance will be available in the future at economical prices.

Item 2. *Changes in Securities and Use of Proceeds*

On December 17, 2002 and in offerings exempt from registration under Section 4(2) of the Securities Act of 1933, as amended, the Partnership converted the existing limited partner interest in the Partnership owned by Crosstex Energy Holdings Inc. into 333,000 common units and 4,667,000 subordinated units in connection with the contribution of the interests of our subsidiaries which hold our operating assets. There have been no other sales of unregistered securities of the Partnership within the past three years.

Item 3. *Defaults Upon Senior Securities*

None.

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

None.

Item 5. *Other Information*

None.

Item 6. *Exhibits and Reports on Form 8-K*

(a) Exhibits

99.1—CEO Certification Pursuant to Section 906 of the Sarbanes-Oxley Act

99.2—CFO Certification Pursuant to Section 906 of the Sarbanes-Oxley Act

(b) Reports on Form 8-K.

On May 5, 2003, Crosstex Energy, L.P. filed a Current Report on Form 8-K (dated as of May 2, 2003) which included its press release as Exhibit 99.1 announcing the execution of a definitive agreement relating to the acquisition of assets from Duke Energy Field Services L.P.

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, on the 14 day of May 2003.

CROSSTEX ENERGY, L.P.

By: Crosstex Energy GP, L.P.,
its general partner

By: Crosstex Energy GP, LLC,
its general partner

By: /s/ Barry E. Davis

Barry E. Davis,
President and Chief Executive Officer

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 quarterly 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 quarterly report;

3. Based on my knowledge, the financial statements, and other financial information included in this quarterly 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 quarterly report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and:

   (a) designated such disclosure controls and procedures 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 quarterly report is being prepared;

   (b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this quarterly report (the "Evaluation Date"); and

   (c) presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation

Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, 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 in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this quarterly report whether there were significant changes in controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: May 14, 2003

/s/ BARRY E. DAVIS

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

I, William W. Davis, Senior 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 quarterly 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 quarterly report;

3. Based on my knowledge, the financial statements, and other financial information included in this quarterly 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 quarterly report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and:

   (a) designated such disclosure controls and procedures 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 quarterly report is being prepared;

   (b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this quarterly report (the "Evaluation Date"); and

   (c) presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, 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 in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this quarterly report whether there were significant changes in controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: May 14, 2003

/s/ WILLIAM W. DAVIS

William W. Davis,
Senior Vice President and Chief Financial Officer (principal
financial and accounting officer)

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EXHIBIT 99.1

CERTIFICATION PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2003
(18 U.S.C. Section 1350)

In connection with the accompanying Quarterly Report of Crosstex Energy, L.P., (the "Partnership") on Form 10-Q for the year ended December 31, 2002, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), 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 Partnership, hereby certify that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

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

Date: May 14, 2003

/s/ BARRY E. DAVIS

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

A signed original of this written statement required by Section 906 has been provided to Crosstex Energy, L.P. and will be retained by Crosstex Energy, L.P. and furnished to the Securities and Exchange Commission or its staff upon request.

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EXHIBIT 99.2

CERTIFICATION PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2003
(18 U.S.C. Section 1350)

In connection with the accompanying Quarterly Report of Crosstex Energy, L.P., (the "Partnership") on Form 10-Q for the year ended December 31, 2002, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, William W. Davis, Chief Financial Officer of Crosstex Energy GP, LLC, the general partner of Crosstex Energy GP, L.P., the general partner of the Partnership, hereby certify that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

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

Date: May 14, 2003

/s/ WILLIAM W. DAVIS

William W. Davis
Chief Financial Officer
(principal financial and accounting officer)

A signed original of this written statement required by Section 906 has been provided to Crosstex Energy, L.P. and will be retained by Crosstex Energy, L.P. and furnished to the Securities and Exchange Commission or its staff upon request.

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