QuickLinks -- Click here to rapidly navigate through this document

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

Form 10-Q

☒ **Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the quarterly period ended September 30, 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	16-1616605
(State of organization)	*(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 November 13, 2003 was 4,358,000 common units and 4,667,000 subordinated units.

TABLE OF CONTENTS

PART I—FINANCIAL INFORMATION

Item 1. *Financial Statements*

CROSSTEX ENERGY, L.P.
(Successor to Crosstex Energy Services, Ltd.)
Consolidated Balance Sheets
(In thousands)

	September 30, 2003	December 31, 2002
	(Unaudited)	
Assets		
Current assets:		
Cash and cash equivalents	$ 156	$ 1,308
Accounts receivable:		
Trade	128,147	104,802
Imbalances	—	79
Related party	1,542	—
Other	772	637
Notes receivable—short term	653	—
Fair value of derivative assets	3,103	2,947
Prepaid expenses and other	1,998	1,225
Total current assets	136,371	110,998
Property and equipment:		
Transmission assets	94,370	50,391
Gathering systems	27,315	22,624
Gas plants	83,706	39,475
Other property and equipment	3,685	2,754
Construction in process	8,250	6,935
Total property and equipment	217,326	122,179
Accumulated depreciation	(20,541)	(12,231)
Total property and equipment, net	196,785	109,948
Fair value of derivative assets	59	155
Intangible assets, net	5,607	5,340
Goodwill, net	4,873	4,873
Investment in limited partnerships	2,081	346
Other assets, net	2,825	778
Total assets	$ 348,601	$ 232,438
Liabilities and Partners' Equity		
Current liabilities:		
Accounts payable and accrued gas purchases	$ 140,954	$ 110,793
Accrued imbalances payable	205	149
Fair value of derivative liabilities	6,070	4,006
Current portion of long-term debt	50	50
Other current liabilities	5,868	4,672
Total current liabilities	153,147	119,670
Long-term debt	43,200	22,500
Fair value of derivative liabilities	316	452
Partners' equity:		
Common unitholders (4,358 and 2,633 units issued and outstanding at September 30, 2003 and December 31, 2002, respectively)	117,427	58,147
Subordinated unitholders (4,667 units issued and outstanding)	35,118	31,829
General partner interest (2% interest with 184 and 149 equivalent units outstanding at September 30, 2003 and December 31, 2002, respectively)	2,771	1,016
Other comprehensive income (loss)	(3,378)	(1,176)
Total partners' equity	151,938	89,816
Total liabilities and partners' equity	$ 348,601	$ 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, except per share amounts)
(Unaudited)

	Three months ended September 30, 2003	Three months ended September 30, 2002	Nine months ended September 30, 2003	Nine months ended September 30, 2002
Revenues:				
Midstream	$ 277,925	$ 110,858	$ 747,270	$ 311,453
Treating	5,273	3,753	15,750	10,631
Total revenues	283,198	114,611	763,020	322,084
Operating costs and expenses:				
Midstream purchased gas	264,035	104,350	715,514	294,025
Treating purchased gas	1,860	1,397	6,311	3,996
Operating expenses	5,462	2,682	12,007	7,732
General and administrative	1,721	2,041	5,112	6,247
Stock based compensation	1,577	33	4,649	33
Impairments	—	—	—	3,150
(Profit) on energy trading activities	(646)	(162)	(1,491)	(2,916)
Depreciation and amortization	4,031	2,150	9,077	6,034
Total operating costs and expenses	278,040	112,491	751,179	318,301
Operating income	5,158	2,120	11,841	3,783
Other income (expense):				
Interest expense, net	(1,321)	(703)	(2,196)	(2,399)
Other income	51	68	50	73
Total other income (expense)	(1,270)	(635)	(2,146)	(2,326)
Net income	$ 3,888	$ 1,485	$ 9,695	$ 1,457
General partner share of net income	$ 450		$ 621	
Limited partners share of net income	$ 3,438		$ 9,074	
Net income per limited partners' unit:				
Basic	$ 0.44		$ 1.22	
Diluted	$ 0.43		$ 1.20	
Weighted average limited partners' units outstanding:				
Basic	7,731		7,445	
Diluted	7,930		7,548	

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.
(Successor to Crosstex Energy Services, Ltd.)
Consolidated Statements of Changes in Partners' Equity
Nine months ended September 30, 2003
(In thousands)
(Unaudited)

	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
Net proceeds from issuance of common units	57,159	—	—	—	57,159
Contributions	—	—	1,266	—	1,266
Stock-based compensation	1,700	2,856	93	—	4,649
Distributions	(2,965)	(5,255)	(225)	—	(8,445)
Net income	3,386	5,688	621	—	9,695
Hedging gains or losses reclassified to earnings	—	—	—	2,056	2,056

Adjustment in fair value of derivatives	—	—	—	(4,258)	(4,258)
Balance, September 30, 2003	$ 117,427	$ 35,118	$ 2,771	$ (3,378)	$ 151,938

See accompanying notes to consolidated financial statements.

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

	Nine months ended September 30,	
	2003	**2002**
Net income	$ 9,695	$ 1,457
Hedging gains or losses reclassified to earnings	2,056	136
Adjustment in fair value of derivatives	(4,258)	(961)
Comprehensive income	$ 7,493	$ 632

See accompanying notes to consolidated financial statements.

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

	Nine months ended September 30,	
	2003	**2002**
Cash flows from operating activities:		
Net income	$ 9,695	$ 1,457
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	9,077	6,034
Impairments	—	3,150
(Income) loss on investment in affiliated partnerships	(173)	13
Noncash stock-based compensation	4,649	33
Changes in assets and liabilities:		
Accounts receivable	(24,943)	(42,447)
Prepaid expenses	(773)	(82)
Accounts payable, accrued gas purchases, and other accrued liabilities	30,217	51,439
Fair value of derivatives	(382)	(4,405)
Other	781	(105)
Net cash provided by operating activities	28,148	15,087
Cash flows from investing activities:		
Additions to property and equipment	(27,135)	(8,346)
Asset purchases	(68,124)	(4,430)
Additions to intangibles and other noncurrent assets	(1,818)	—
Investment in affiliated partnerships	(1,443)	—
Distributions from (investments in) affiliated partnerships	(120)	87
Net cash used in investing activities	(98,640)	(12,689)
Cash flows from financing activities:		
Proceeds from bank borrowings	238,600	186,300
Payments on bank borrowings	(217,900)	(203,050)

Debt refinancing costs		(1,340)		—
Proceeds from issuance of common units, net of offering costs		57,159		—
Distributions to partners		(8,445)		—
Contributions from partners		1,266		14,000
Net cash provided by (used in) financing activities		69,340		(2,750)
Net increase (decrease) in cash and cash equivalents		(1,152)		(352)
Cash and cash equivalents, beginning of period		1,308		352
Cash and cash equivalents, end of period	$	156	$	0
Cash paid for interest	$	1,998	$	1,776
Noncash transactions—stock based compensation	$	4,649	$	33

See accompanying notes to consolidated financial statements.

Crosstex Energy, L.P.

(Successor to Crosstex Energy Services, Ltd.)
Notes to Consolidated Financial Statements
September 30, 2003
(Unaudited)

(1) General

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

Crosstex Energy, L.P. ("the Partnership") is a midstream natural gas 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, Inc. ("Crosstex Energy", formerly Crosstex Energy Holdings Inc.). Crosstex Energy 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 Energy including (i) the Jonesville and Clarkson gas plants, (ii) the Enron receivable, 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.

See Note 5 for a discussion of the Partnership's September 2003 sale of additional common units.

(b) Employee Incentive Plans

The Partnership's managing general partner has granted unit options pursuant to a long-term incentive plan for its employees, directors and affiliates who perform services for the Partnership. Additionally, Crosstex Energy, Inc. has granted common stock options under its 2000 Stock Option

Plan for employees, directors and affiliates who perform services for the Partnership. The Partnership applies the provisions of Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees* (APB No. 25), and the related interpretations in accounting for these plans. In accordance with APB No. 25 for fixed option awards, compensation is recorded to the extent the fair value of the stock exceeds the exercise price of the option at the measurement date. Compensation expense of $4,649,000 and $33,000 was recognized in the nine months ended September 30, 2003 and 2002, respectively. See below for a discussion of the modification of certain Crosstex Energy options in 2003.

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 would have been as follows:

	Three months ended September 30,	Nine months ended September 30,

	2003	2002	2003	2002
Net income, as reported	$ 3,888	$ 1,485	$ 9,695	$ 1,457
Add: Stock-based employee compensation expense included in reported net income	1,577	33	4,649	33
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards	(1,655)	(120)	(4,918)	(273)
Pro forma net income	$ 3,810	$ 1,398	$ 9,426	$ 1,217

	Three months ended September 30,		Nine months ended September 30,	
	2003	2002	2003	2002
Net income per limited partner unit, as reported:				
Basic	$ 0.44	—	$ 1.22	—
Diluted	$ .043	—	$ 1.20	—
Pro forma income per limited partner unit:				
Basic	$ 0.43	—	$ 1.18	—
Diluted	$ 0.42	—	$ 1.17	—

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 unit grants by the Partnership in the nine months ended September 30, 2003:

	Nine months ended September 30, 2003
Options granted	91,910
Dividend yield	10%
Expected volatility	24%
Risk free interest rate	2.88%
Expected life	5 years
Contractual life	10
Weighted average of fair value of options granted	$ 2.76

In addition to options granted, the Partnership approved the issuance of 48,000 restricted unit grants during the nine months ended September 30, 2003. Compensation expense is recognized over the five year vesting of these restricted units.

Crosstex Energy, Inc. modified certain outstanding options attributable to its common shares 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 Energy 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. The Partnership will account for the modified options until the holders elect to cash out the options or the election to cash out the options lapses. Crosstex Energy 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 recognized 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 $1.6 million and $4.6 million for the three and nine month periods ended September 30, 2003, respectively.

(c) Earnings per unit and anti-dilutive computations

Basic earnings per unit was computed by dividing net income available to limited partners, by the weighted average number of limited partner units outstanding. The general partner's share of net income includes incentive distributions of $380,000 and $436,000 earned in the three and nine months ended September 30, 2003, respectively. 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 three and nine-month periods ended September 30, 2003 (in thousands):

	Three months ended September 30, 2003	Nine months ended September 30, 2003
Basic earnings per unit:		
Weighted average limited partner units outstanding	7,731	7,445
Dilutive earnings per unit:		
Weighted average limited partner units outstanding	7,731	7,445
Dilutive effect of exercise of options outstanding	199	103
Dilutive units	7,930	7,548

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 ending after December 15, 2003. The Partnership is evaluating its ownership interests in joint ventures and limited partnerships that are currently accounted for using the equity method of accounting to determine whether FIN No. 46 will require the consolidation of any of these investments.

(2) Significant Acquisitions

On June 30, 2003, we completed the acquisition of certain assets from Duke Energy Field Services, L.P. for $68.1 million, including the effect of certain purchase price adjustments. The assets acquired included: the Mississippi pipeline system, a 12.4% interest in the Seminole gas processing plant, the Conroe gas plant and gathering system and the Black Warrior pipeline system. We have accounted for this acquisition as a business combination in accordance with SFAS No. 141, Business Combinations. We have utilized the purchase method of accounting for this acquisition with an acquisition date of June 30, 2003. The purchase price and allocation thereof is as follows (in thousands):

Purchase price to DEFS	$	66,356
Direct acquisition costs		1,768
Total Purchase Price	$	68,124
Current assets acquired	$	426
Liabilities assumed		(813)
Property plant and equipment		67,589
Intangible assets		922
Total Purchase Price	$	68,124

Intangible assets relate to customer relationships and will be amortized over seven years. Operating results for the DEFS assets are included in the Statements of Operations since June 30, 2003. Pro forma results of operations as if the acquisition from DEFS had been acquired on January 1, 2002 are as follows:

	Three Months Ended September 30, 2002	Nine Months Ended September 30, 2003	Nine Months Ended September 30, 2002
	(in thousands except per share amounts)		
Revenue	$ 152,923	$ 869,342	$ 421,027
Net income	$ 2,388	$ 10,685	$ 2,556
Net income per Limited partner unit	N/A	$ 1.37	N/A

On June 6, 2002, CES acquired 70 miles of then-inactive pipeline from Florida Gas Transmission Company for $1,474,000 in cash and a $800,000 note payable. On June 7, 2002, CES acquired the Pandale gathering system which is connected to two treating plants, one of which (the "Will-O-Mills Plant") was half-owned by the Partnership, from Star Field Services for $2,156,000 in cash. The Partnership purchased the other one-half interest in the Will-O-Mills Plant on December 30, 2002 for $2,200,000 in cash.

On December 19, 2002, CES acquired the Vanderbilt system, consisting of approximately 200 miles of gathering pipeline located near our Gulf Coast System from an indirect subsidiary of Devon Energy Corporation, for $12,000,000 cash.

(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, a 50% interest in J.O.B. J.V., and a 50% interest in Crosstex Denton County Gathering 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

Description of Indebtedness

Bank Credit Facility. In June 2003, our operating partnership, Crosstex Energy Services, L.P., entered into a $100 million senior secured credit facility with Union Bank of California, N.A. (as a lender and as administrative agent) and other lenders, which was increased to $120 million in October 2003, consisting of the following two facilities:

- a $70.0 million senior revolving acquisition facility; and
- a $50.0 million senior secured revolving working capital and letter of credit facility.

The acquisition facility was used for the DEFS acquisition and will be used to finance the acquisition and development of gas gathering, treating and processing facilities, as well as general partnership purposes. The acquisition facility will mature in June 2006, at which time it will terminate and all outstanding amounts shall be due and payable. Amounts borrowed and repaid under the acquisition credit facility may be reborrowed.

The working capital and letter of credit facility will be used for ongoing working capital needs, letters of credit, distributions to partners and general partnership purposes, including future acquisitions and expansions. At September 30, 2003 we had $22.5 million of letters of credit issued under the $50 million working capital and letter of credit facility leaving approximately $27.5 million available for future issuances of letters of credit and/or cash borrowings. The aggregate amount of borrowings under the working capital and letter of credit 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 $10.0 million sublimit for cash borrowings. This facility will mature in June 2006, at which time it will terminate and all outstanding amounts shall be due and payable. Amounts borrowed and repaid under the working capital and letter of credit 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 each year.

The obligations under the bank 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, and ranks *pari passu* in right of payment with the senior secured notes. The bank credit facility is guaranteed by certain of our subsidiaries and by us. We may prepay all loans under the bank credit facility at any time without premium or penalty (other than customary LIBOR breakage costs), subject to certain notice requirements.

Indebtedness under the acquisition facility and the working capital and letter of credit facility bear interest at our operating partnership's option at the administrative agent's reference rate plus 0.25% to 1.50% or LIBOR plus 1.75% to 3.00%. 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. Our operating partnership will 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 bank credit facility contains various covenants that, among other restrictions, limit 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;
- change the nature of its business;
- enter into certain commodity contracts;
- make certain amendments to our operating partnership's partnership agreement; and
- engage in transactions with affiliates.

The bank credit facility also contains covenants requiring us to maintain:

- a maximum ratio of total funded debt to consolidated EBITDA (each as defined in the bank credit facility), measured quarterly on a rolling four-quarter basis, of 3.75 to 1 through March 31, 2004, declining to 3.5 to 1 beginning June 30, 2004, 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 $60 million, plus one-half of certain equity contribution proceeds received after December 31, 2002.

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

- failure to pay any principal, interest, fees, expenses or other amounts when due;
- failure to observe any agreement, obligation, or covenant in the credit agreement, subject to cure periods for certain failures;

- certain judgments against us or any of our subsidiaries, in excess of certain allowances;
- certain ERISA events involving us or our subsidiaries;
- cross defaults to certain material indebtedness;

- 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.

Senior Secured Notes. In June 2003, our operating partnership entered into a master shelf agreement with an institutional lender pursuant to which it issued $30.0 million aggregate principal amount of senior secured notes with an interest rate of 6.95% and a maturity of seven years. In July 2003, our operating partnership issued $10.0 million aggregate principal amount of senior secured notes pursuant to the master shelf agreement with an interest rate of 6.88% and a maturity of seven years.

The following is a summary of the material terms of the senior secured notes.

The notes represent senior secured obligations of our operating partnership and will rank at least *pari passu* in right of payment with the bank credit facility. The notes are secured, on an equal and ratable basis with obligations of the operating partnership under the credit facility, 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 senior secured notes are guaranteed by our operating partnership's subsidiaries and us.

The senior secured notes are redeemable, at our operating partnership's option and subject to certain notice requirements, at a purchase price equal to 100% of the principal amount together with accrued interest, plus a make-whole amount determined in accordance with the master shelf agreement.

The master shelf agreement relating to the notes contains substantially the same covenants and events of default as the bank credit facility.

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

The Partnership was in compliance with all debt covenants at December 31, 2002 and September 30, 2003, and expects to be in compliance with debt covenants for the next twelve months.

Intercreditor and Collateral Agency Agreement. In connection with the execution of the master shelf agreement in June 2003, the lenders under the bank credit facility and the initial purchasers of the

senior secured notes entered into an Intercreditor and Collateral Agency Agreement, which was acknowledged and agreed to by our operating partnership and its subsidiaries. This agreement appointed Union Bank of California, N.A. to act as collateral agent and authorized Union Bank to execute various security documents on behalf of the lenders under the bank credit facility and the initial purchases of the senior secured notes. This agreement specifies various rights and obligations of lenders under the bank credit facility, holders of senior secured notes and the other parties thereto in respect of the collateral securing Crosstex Energy Services, L.P.'s obligations under the bank credit facility and the master shelf agreement.

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 September 30, 2003 and December 31, 2002, long-term debt consisted of the following (in thousands):

	September 30, 2003	December 31, 2002
Acquisition credit facility, interest based at prime plus an applicable margin	$ 2,500	$ 1,750
Acquisition credit facility, interest based on LIBOR plus an applicable margin	—	20,000
Senior Secured Notes, weighted average interest rate of 6.93%	40,000	
Note payable to Florida Gas Transmission Company	750	800
	43,250	22,550
Less current portion	(50)	(50)
Debt classified as long-term	$ 43,200	$ 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

Sale of Additional Common Units

In September 2003, the Partnership completed a public offering of 1,725,000 common units at $35.97 per common units. The Partnership received net proceeds of approximately $59.1 million, including an approximate $1.3 million capital contribution by its general partner. The net proceeds were used to repay borrowings outstanding under the bank credit facility of our operating partnership.

Cash Distributions

The Partnership announced on October 16, 2003 that it will make its third quarter distribution on its common and subordinated units of $0.70 on November 14, 2003, payable to holders of record on October 30, 2003.

(6) Derivatives

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 September 30, 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), NYMEX Settlement (NYMEX), Reliant East Inside FERC (Reliant E IF), Texas Eastern SouthTexas 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 December 2004, with no single contract longer than 16 months. The Partnership's counterparties to hedging contracts include Morgan Stanley, BP, Williams, Duke 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.

September 30, 2003

Transaction type	Total volume	Pricing terms	Remaining term of contracts	Fair value
Natural gas swap-cash flow hedge	(370,000)	$4.01 vs. Reliant E IF to $5.00 vs. Reliant E IF	October 2003-June 2004	$ 125,145
Natural gas swap-cash flow hedge	1,748,000	$4.43 vs. HSC IF to $6.545 vs HSC IF	October 2003-December 2004	(1,811,955)
Natural gas swap-cash flow hedge	4,955,000	$4.718 vs. NYMEX to $6.11 vs NYMEX	October 2003-December 2004	(1,666,095)
Natural gas swap-cash flow hedge	(456,000)	$5.92 vs TET STx IF	November 2003-March 2004	442,833
Marketing trading transaction swaps	(861,000)	$3.14 vs. TET Etx If to $6.24 vs. TET Etx IF	October 2003-June 2004	(219,197)
Marketing trading transaction swaps	1,086,000	$3.935 vs. HSC IF to $6.145 vs. HSC IF	October 2003-December 2004	(538,215)

December 31, 2002

Transaction type	Total volume	Pricing terms	Remaining term of contracts	Fair value
Natural gas swap-cash flow hedge	(500,000)	$3.285 vs. Reliant E IF to $4.01 vs. Reliant E IF	January 2003-April 2004	$ (421,800)
Natural gas swap-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 E IF to $3.635 vs. Reliant E 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 activities that are accounted for as energy trading contracts are included in fair value of derivative assets and liabilities. Assets and liabilities related to off-system energy trading contracts were as follows:

	September 30, 2003	December 31, 2002
	(In thousands)	
Fair value of derivative assets:		
Current	$ 1,280	$ 2,947
Long-term	42	155
Fair value of derivative liabilities:		
Current	$ 1,365	$ 3,046
Long-term	39	236

The Partnership estimates the fair value of its off-system energy trading contracts using prices actively quoted. The estimated fair value of derivatives 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
September 30, 2003	$ (85)	$ 3	—	$ (82)
December 31, 2002	$ (99)	$ (81)	—	$ (180)

(7) Transactions with Related Parties

General and Administrative Expense Cap

The Partnership has a $6.0 million annual ($1.5 million quarterly) general and administrative cap for the twelve month period ending December 2003, per the partnership agreement. Crosstex Energy bears the cost of any excess general and administrative expenses. During the three months and nine months ended September 30, 2003, the Partnership had excess expenses of approximately $0.9 million and $2.1 million, respectively. The general partner is also reimbursed for direct charges it incurs on behalf of Partnership business development activities. Such charges totaled $0.6 million for the nine months ended September 30, 2003 and are included in general and administrative expenses.

Crosstex Pipeline

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

- During the quarters ended September 30, 2003 and 2002, the Partnership bought natural gas from CPC in the amount of approximately $2.3 million and $0.9 million and paid for transportation of approximately $7,000 and $7,000 respectively, to CPC. For the nine months ended September 30, 2003 and 2002, the Partnership bought natural gas from CPC in the

amount of approximately $6.2 million and $3.1 million and paid for transportation of approximately $31,000 and $23,000, respectively, to CPC.

- During the quarters ended September 30, 2003 and 2002, the Partnership received a management fee from CPC in the amount of approximately $31,000 each quarter and $94,000 for each nine month period ended September 30, 2003 and 2002.

- During the quarters ended September 30, 2003 and 2002, the Partnership received distributions from CPC in the amount of approximately $26,000 and $13,000 respectively. For the nine month periods ended September 30, 2003 and 2002, the Partnership received distributions from CPC in the amount of approximately $84,000 and $64,000.

Crosstex Denton County Gathering J.V.

During the nine and three months ended September 30, 2003, the Partnership received a management fee from Crosstex Denton County Gathering J.V. ("CDC") of $80,000 and $30,000, respectively. The Partnership also received distributions of $15,000 from CDC for the nine and three-month periods ending September 30, 2003.

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 Energy Partners IV, L.P. and Yorktown Energy Partners V, L.P. (collectively, "Yorktown") in Camden. Yorktown is an equity holder of Crosstex Energy, Inc. During the quarters ended September 30, 2003 and 2002, the Partnership purchased natural gas from Camden in the amount of approximately $1.5 million and $3.8 million, respectively, and received approximately $29,000 and $182,000 in treating fees from Camden. And for the nine months ended September 30, 2003 and 2002, the Partnership purchased natural gas from Camden in the amount of approximately $7.0 million and $7.4 million, respectively, and received approximately $167,000 and $364,000 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 Mississippi System, the Conroe System, the Gulf Coast System, the Corpus Christi System, the Gregory gathering system located around the Corpus Christi area, the Arkoma system in Oklahoma, the Vanderbilt System 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 September 30, 2003:			
Sales to external customers	$ 277,925	$ 5,273	$ 283,198
Intersegment sales	1,583	(1,583)	—
Interest expense	1,295	26	1,321
Depreciation and amortization	3,266	765	4,031
Segment profit (loss)	3,016	871	3,888
Segment assets	335,519	13,082	348,601
Capital expenditures	8,433	2,259	10,692
Three months ended September 30, 2002:			
Sales to external customers	$ 110,858	$ 3,753	$ 114,611
Intersegment sales	744	(744)	—
Interest expense	680	23	703
Depreciation and amortization	1,483	667	2,150
Segment profit (loss)	4,111	(2,626)	1,485
Segment assets	206,987	7,875	214,862
Capital expenditures	2,748	(377)	2,371
Nine months ended September 30, 2003:			
Sales to external customers	$ 747,270	$ 15,750	$ 763,020
Intersegment sales	5,492	(5,492)	—
Interest expense	2,151	45	2,196
Depreciation and amortization	6,981	2,096	9,077
Segment profit (loss)	7,446	2,248	9,695
Segment assets	335,519	13,082	348,601
Capital expenditures	20,512	6,623	27,135
Nine months ended September 30, 2002:			
Sales to external customers	$ 311,453	$ 10,631	$ 322,084
Intersegment sales	2,780	(2,780)	—
Interest expense	2,320	79	2,399
Depreciation and amortization	4,033	2,001	6,034
Segment profit (loss)	3,176	(1,719)	1,457
Segment assets	206,987	7,875	214,862
Capital expenditures	8,064	282	8,346

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, 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 nine months ended September 30, 2003, 77% of our gross margin was generated in the Midstream division, with the balance in the Treating division, and approximately 74% 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 and treating and processing plants. From January 1, 2000 through September 30, 2003, we have invested approximately $211.0 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 as well as fees earned from recovering carbon dioxide and natural gas liquids at a non-operated processing plant. We generate revenues from five primary sources:

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

- processing natural gas at our processing plants;
- providing producer services;
- treating natural gas at our treating plants; and
- recovering carbon dioxide and natural gas liquids at a non-operated processing plant.

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 Partnership's principal Midstream assets are as follows:

- the Gulf Coast system, consisting of approximately 500 miles of pipeline located in south Texas;
- the CCNG Transmission system, consisting of approximately 300 miles of pipeline located in south Texas;
- the Gregory gathering system, consisting of approximately 300 miles of pipeline located in the Corpus Christi. Texas Bay area;

- the Vanderbilt system, consisting of approximately 200 miles of pipeline located in south Texas;
- the Conroe processing plant located in south Texas;
- the Arkoma gathering system, consisting of approximately 100 miles of pipeline located in eastern Oklahoma;
- the Mississippi gathering system, consisting of approximately 600 miles of pipeline located in central Mississippi;
- a 12.4% non-operating interest in the Seminole carbon dioxide processing plant, located in Gaines County, Texas;

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 nine months ended September 30, 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.

	Nine Months ended September 30, 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	20.2	1.9	22.1	—
CCNG transmission system	43.0	0.5	43.5	—
Gregory gathering system(1)	39.3	1.7	35.4	—
Vanderbilt system(1)	7.8	8.8	14.1	—
Conroe system(1)	0.6	1.0	1.3	
Arkoma gathering system	—	3.3	3.3	—
Mississippi system	7.4	0.3	7.7	
Producer services(2)	69.7	2.2	71.9	—

(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 activities.

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 nine months ended September 30, 2003, we purchased approximately 18% 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, up to 100,000 MMcfd, is delivered to two customers 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 nine months ended September 30, 2003, we purchased approximately 82% 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.

We own a 12.4% non-operating interest in the Seminole gas processing plant located in Gaines County, Texas. A portion of our revenues at the facility are based on a percentage of the NGL's recovered at the facility. Therefore, we have commodity price exposure due to variances in the prices of NGL's. In the third quarter of 2003, our share of NGL's totaled 1,443,000 gallons at an average price of $.4337 per gallon.

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 50 independent producers. 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 60% of the operating income in our Treating division for the nine months ended September 30, 2003;
- a fixed fee for operating the plant for a certain period, which accounted for approximately 34% of the operating income in our Treating division for the nine months ended September 30, 2003; or
- a fee arrangement in which the producer operates the plant, which accounted for approximately 6% of the operating income in our Treating division for the nine months ended September 30, 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, 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 us, and all other expenses necessary or appropriate to the conduct of the business of, and allocable to, us. Our partnership agreement provides that our general partner determines the expenses that are allocable to us in any reasonable manner determined by our general partner in its sole discretion. For the 12 month period ending in December 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, 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 average unit value for the first, second and third quarters of 2003 of $23.25, $29.54 and $36.95 per unit, respectively, total compensation expense was approximately $4.6 million, which has been recorded by the Partnership as non-cash stock based compensation expense in the nine months ended September 30, 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 DEFS acquisition, the Vanderbilt system and the Hallmark lateral. We acquired the DEFS assets in June 2003 for approximately $68.1 million. The DEFS assets consist of a gathering system approximately 600 miles in length in Mississippi, a gathering system in Alabama approximately 125 miles in length, a processing plant and 10 mile gathering system in Montgomery County, Texas, and a 12.4% interest in the Seminole processing plant in Gaines County, Texas. We acquired the Vanderbilt system in December 2002 for a purchase price of $12 million. The Vanderbilt system consists of approximately 200 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 8.8% in the first nine months 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.

Part of our fee from the Seminole gas plant is based on a portion of the NGLs produced, and, therefore, is subject to commodity price risks.

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

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 (in thousands).

	Three months ended September 30,		Nine months ended September 31,	
	2003	2002	2003	2002
Midstream revenues	$ 277.9	$ 110.9	$ 747.3	$ 311.5
Midstream purchased gas	264.0	104.3	715.5	294.0
Midstream gross margin	13.9	6.6	31.8	17.5
Treating revenues	5.3	3.7	15.7	10.6
Treating purchased gas	1.9	1.4	6.3	4.0
Treating gross margin	3.4	2.3	9.4	6.6
Total gross margin	$ 17.3	$ 8.9	$ 41.2	$ 24.1
Midstream Volumes (MMBtu/d):				
Gathering and transportation	675,000	407,000	643,000	393,000
Processing	134,000	83,000	126,000	87,000
Producer services	274,000	225,000	263,000	229,000
Treating Volumes (MMBtu/d)	94,000	104,000	91,000	99,000

Three Months Ended September 30, 2003 Compared to Three Months Ended September 30, 2002

Revenues. Midstream revenues were $277.9 million for the quarter ended September 30, 2003 compared to $110.9 million for the quarter ended September 30, 2002, an increase of $167.0 million, or 151%. The addition of the DEFS assets ($45.0 million) along with the initiation of service at the Vanderbilt system ($33.8 million), which were not in service in 2002, added $78.8 million of revenue in the third quarter of 2003. An increase in natural gas prices from an average Houston Ship Channel Index price of $4.95 per MMBtu in the third quarter of 2003 compared to $3.19 per MMBtu in the third quarter of 2002, caused a $63.4 million increase in revenues. Additional increases in revenue of $34.7 million were generated at Gregory Gathering, Gregory Processing, CCNG Transmission and Arkoma gathering, due to new volumes into the systems from producer drilling and additional sales volumes to new markets. These increases were partially offset by a decrease in revenue of $9.9 million at the Gulf Coast system due to a decrease in volume.

Treating revenues were $5.3 million for the quarter ended September 30, 2003 compared to $3.8 million in the same period in 2002, an increase of $1.5 million, or 41%. $1.1 million of the increase was due to 19 new plants placed in service and increases in the price of natural gas contributed $0.9 million of the increase. These increases were partially offset by volume decreases at two plants, which reduced revenue by approximately $0.2 million and the removal of 5 plants from service which reduced revenue by approximately $0.2 million.

Purchased Gas Costs. Midstream purchased gas costs were $264.0 million for the quarter ended September 30, 2003 compared to $104.3 million for the quarter ended September 30, 2002, an increase of $159.7 million, or 153%. Costs increased by $58.2 million due to the increase in natural gas prices. Costs of $72.5 million were generated by the addition of the DEFS assets ($40.5 million) and the Vanderbilt system ($32.5 million) that were not in operation in the second quarter of 2002. Additional costs were generated at Gregory Gathering, Gregory Processing, CCNG Transmission, and Arkoma gathering of $33.2 million due to new volumes into the systems from producer drilling and to fulfill new market demands. These increases in costs were partially offset by a decrease in purchased gas costs of $9.2 million at the Gulf Coast system due to a decrease in volume.

Treating purchased gas costs were $1.9 million for the quarter ended September 30, 2003 compared to $1.4 million in the comparable period in 2002, an increase of $0.5 million or 33%. The increase in natural gas prices resulted in a $0.7 million increase, which was partially offset by a decrease in treating volumes at three volume sensitive plants.

Operating Expenses. Operating expenses were $5.5 million for the quarter ended September 30, 2003, compared to $2.7 million for the quarter ended September 30, 2002, an increase of $2.8 million, or 104%. The increase was primarily due to the addition of the DEFS assets, the initiation of service at the Vanderbilt system, the Hallmark lateral, and new treating plants in service.

General and Administrative Expenses. General and administrative expenses were $1.7 million for the quarter ended September 30, 2003 compared to $2.0 million for the quarter ended September 30, 2002, a decrease of $0.3 million, or 16%. The decrease was due to the $6 million annual general and administrative cap in the twelve month period ending December 2003, per the partnership agreement. Had the cap not been in place, general and administrative expenses would have been $2.7 million for the quarter ended September 30, 2003.

Stock-based Compensation. Stock-based compensation was $1.6 million for the quarter ended September 30, 2003, compared to $33,000 in the second quarter of 2002. The 2003 stock-based compensation primarily 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. Crosstex Energy, Inc. is responsible for paying the intrinsic value of the options for the holders who elect to cash out their options.

(Profit) on Energy Trading Activities. The profit on energy trading was $0.6 million for the quarter ended September 30, 2003 compared to $0.2 million for the quarter ended September 30, 2002, an increase of $0.4 million. Included in these amounts were realized margins on delivered volumes in the producer services "off-system" gas marketing operations of $0.6 million in the third quarter of 2003 and $0.5 million in the third quarter of 2002. In addition, losses of $0.3 million relating primarily to options bought and/or sold in the management of the Partnership's Enron position were booked in 2002.

Depreciation and Amortization. Depreciation and amortization expense was $4.0 million for the quarter ended September 30, 2003 compared to $2.2 million for the quarter ended September 30, 2002, an increase of $1.9 million, or 87%. The increase is primarily due to an increase in fixed assets of $217 million from September 30, 2002 to September 30, 2003 (including the June 2003 acquisition of assets from Duke Energy Field Services).

Interest Expense. Interest expense was $1.3 million for the quarter ended September 30, 2003 compared to $0.7 million for the quarter ended September 30, 2002, an increase of $0.6 million, or 88%. The increase is due to a additional bank debt needed to fund the DEFS acquisition until proceeds from the follow-on offering were received and used to pay down bank indebtedness in September 2003.

Net Income (Loss). Net income (loss) for the quarter ended September 30, 2003 was $3.9 million compared to $1.5 million for the quarter ended September 30, 2002, an increase of $2.4 million. This increase is primarily due to the increase in gross margin of $8.4 million partially offset by increases in operating expenses ($2.8 million), stock-based compensation expense ($1.5 million) and depreciation and amortization ($1.9 million).

Nine Months Ended September 30, 2003 Compared to Nine Months Ended September 30, 2002

Revenues. Midstream revenues were $747.3 million for the nine months ended September 30, 2003 compared to $311.5 million for the nine months ended September 30, 2002, an increase of $435.8 million, or 140%. This increase is primarily due to an increase in natural gas prices from an

average NYMEX settlement price was $5.51 per MMBtu for the first nine months of 2003 compared to $2.97 per MMBtu in the first nine months of 2002, which caused a $259.5 million increase in revenues. Additional revenue of $119.6 million was generated by the DEFS assets ($45.0 million) and the Vanderbilt system ($74.6 million), which were not in operation in the first nine months of 2002. Additional increases in revenue of $69.0 million was generated at Gregory Gathering, Gregory Processing, CCNG Transmission, and Arkoma gathering due to new volumes into the systems from producer drilling and additional sales volumes from new markets. These increases were partially offset by a decrease in revenue of $20.5 million at the Gulf Coast system due to a decrease in volume.

Treating revenues were $15.8 million for the nine months ended September 30, 2003 compared to $10.6 million in the same period in 2002, an increase of $5.2 million, or 48%. Increases in the price of natural gas contributed $3.3 million of the increase, $2.7 million of the increase was due to 23 new plants placed in service, and $0.9 million increase was due to volume increases at two plants. This increase was partially offset by volume decreases at two plants, which reduced revenue by $0.8 million and the removal of 10 plants from service which reduced revenue by $0.9 million.

Purchased Gas Costs. Midstream purchased gas costs were $715.5 million for the nine months ended September 30, 2003 compared to $294.0 million for the nine months ended September 30, 2002, an increase of $421.5 million, or 143%. Costs increased by $252.1 million due to the increase in natural gas prices. In addition, costs of $116.7 million were generated by the DEFS assets ($40.5 million) and the Vanderbilt system ($71.2 million) that were not in operation in the first nine months of 2002. Additional costs were generated at Gregory Gathering, Gregory Processing, CCNG Transmission, and Arkoma gathering of $76.8 million due to new volumes into the systems from producer drilling and to fulfill new market demands. These increases in costs were partially offset by a decrease in purchased gas costs of $19.1 million at the Gulf Coast system due to a decrease in volume.

Treating purchased gas costs were $6.3 million for the nine months ended September 30, 2003 compared to $4.0 million in the comparable period in 2002, an increase of $2.3 million, or 58%. The increase in natural gas prices resulted in a $3.0 million increase, which was partially offset by a decrease in treating volumes at two volume sensitive plants.

Operating Expenses. Operating expenses were $12.0 million for the nine months ended September 30, 2003, compared to $7.7 million for the nine months ended September 30, 2002, an increase of $4.3 million, or 55%. The increase was primarily due to the incorporation of the DEFS assets and the initiation of service from the Vanderbilt system, the Hallmark lateral, and new treating plants in service.

General and Administrative Expenses. General and administrative expenses were $5.1 million for the nine months ended September 30, 2003 compared to $6.2 million for the nine months ended September 30, 2002, a decrease of $1.1million, or 18%. The decrease was due to the $6 million annual general and administrative cap in the twelve month period ending December 2003, per the partnership agreement. Had the cap not been in place, general and administrative expenses would have been $7.2 million for the nine months ended September 30, 2003.

Stock-based Compensation. Stock-based compensation was $4.6 million for the nine months ended September 30, 2003, compared to $33,000 in the same period of 2002. This stock-based compensation primarily 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. Crosstex Energy, Inc. is responsible for paying the intrinsic value of the options for the holders who elect to cash out their options.

Impairments. There was no impairment expense in the first nine months 2003 compared to $3.2 million in the first nine months 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 nine months 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 declines in cash flows at the time the impairment charges were taken.

(Profit) Loss on Energy Trading Activities. The profit on energy trading was $1.5 million for the nine months ended September 30, 2003 compared to $2.9 million for the nine months ended September 30, 2002, a decrease of $1.4 million. Included in these amounts were realized margins on delivered volumes in the producer services "off-system" gas marketing operations of $1.9 million in the first nine months of 2003 and $1.4 million in the first nine months of 2002. In addition, gains of $1.5 million relating primarily to options bought and/or sold in the management of the Partnership's Enron position were booked in 2002.

Depreciation and Amortization. Depreciation and amortization expense was $9.1 million for the nine months ended September 30, 2003 compared to $6.0 million for the nine months ended September 30, 2002, an increase of $3.1 million, or 50%. The increase is primarily due to an increase in fixed assets of $217 million from September 30, 2002 to September 30, 2003 (including the acquisition of assets from Duke Energy Field Services which was completed on June 30, 2003).

Interest Expense. Interest expense was $2.2 million for the nine months ended September 30, 2003 compared to $2.4 million for the nine months ended September 30, 2002, a decrease of $0.2 million, or 8%. The decrease is due to a reduction in bank debt from the proceeds of the initial public offering.

Other Income (Expense). Other income (expense) includes costs associated with a lawsuit settlement of $0.1 million offset by income from affiliated partnerships

Net Income (Loss). Net income for the nine months ended September 30, 2003 was $9.7 million compared to $1.5 million for the nine months ended September 30, 2002, an increase of $8.2 million. The principal reasons for this increase were an increase in gross margin of $17.1 million and an absence of impairments in 2003 as compared to impairments of $3.2 million in 2002, offset principally by increases in stock based compensation ($4.6 million), operating expenses ($4.3 million) and depreciation and amortization expense ($3.0 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 contained in our Annual Report on Form 10-K for the year ended December 31, 2002.

Management's Use of Estimates. The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America requires management of the Partnership to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the

reported amounts of revenues and expenses during the period. Actual results could differ from these estimates.

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 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 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 $28.1 million and $15.1 million for the nine months ended September 30, 2003 and 2002, respectively. Net cash provided by operating activities in 2003 increased principally due to higher income before non-cash expenses (depreciation, amortization, impairments and non-cash stock-based compensation) of $12.6 million.

Net cash used in investing activities was $98.6 million and $12.7 million for the nine months ended September 30, 2003 and 2002, respectively. Net cash used in investing activities during 2003 related to the Duke acquisition ($68.1 million) as well as internal growth projects, and during 2002 primarily related to internal growth projects. The primary internal growth projects referred to for the 2003 nine-month period were the Gregory plant expansion, improvements to the Vanderbilt system, and buying, refurbishing and installing treating plants. The main projects in the 2002 period were the purchase and connection of the Hallmark system, the Calpine interconnect and a line extension at the Gregory plant.

Net cash provided by (used in) financing activities was $69.3 million and ($2.8) million for the nine months ended September 30, 2003 and 2002, respectively. Financing activities in 2003 relate principally to the funding of the Duke assets acquisition. Financing activities during 2002 primarily represented funding or refunding of the partnership's debt and working capital needs.

September 2003 Sale of Common Units. In September 2003, the Partnership completed a public offering of 1,725,000 common units at $35.97 per common units. The Partnership received net proceeds of approximately $59.1 million, including an approximate $1.3 million capital contribution by its general partner. The net proceeds were used to repay borrowings outstanding under the bank credit facility of our operating partnership.

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 60,000 Mcf/d at an estimated cost of approximately $7.0 million.

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 Indebtedness

Bank Credit Facility. In June 2003 our operating partnership, Crosstex Energy Services, L.P., entered into a $100 million senior secured credit facility with Union Bank of California, N.A. (as a lender and as administrative agent) and other lenders which was increased to $120 million in October 2003, consisting of the following two facilities:

- a $70.0 million senior secured revolving acquisition facility; and

- a $50.0 million senior secured revolving working capital and letter of credit facility.

The acquisition facility was used for the DEFS acquisition and will be used to finance the acquisition and development of gas gathering, treating and processing facilities, as well as general partnership purposes. The acquisition facility will mature in June 2006, at which time it will terminate and all outstanding amounts shall be due and payable. Amounts borrowed and repaid under the acquisition credit facility may be reborrowed.

The working capital and letter of credit facility will be used for ongoing working capital needs, letters of credit, distributions to partners and general partnership purposes, including future acquisitions and expansions. At September 30, 2003 we had $22.5 million of letters of credit issued under the $50 million working capital and letter of credit facility, leaving approximately $27.5 million available for future issuances of letters of credit and/or cash borrowings. The aggregate amount of borrowings under the working capital and letter of credit 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 $10.0 million sublimit for cash borrowings. This facility will mature in June 2006, at which time it will terminate and all outstanding amounts shall be due and payable. Amounts borrowed and repaid under

the working capital and letter of credit 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 each year.

The obligations under the bank 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, and ranks *pari passu* in right of payment with the senior secured notes. The bank credit facility is guaranteed by certain of our subsidiaries and by us. We may prepay all loans under the bank credit facility at any time without premium or penalty (other than customary LIBOR breakage costs), subject to certain notice requirements.

Indebtedness under the acquisition facility and the working capital and letter of credit facility bear interest at our operating partnership's option at the administrative agent's reference rate plus 0.25% to 1.50% or LIBOR plus 1.75% to 3.00%. 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. Our operating partnership will 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 bank credit facility contains various covenants that, among other restrictions, limit 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;
- change the nature of its business;
- enter into certain commodity contracts;
- make certain amendments to our operating partnership's partnership agreement; and
- engage in transactions with affiliates.

The bank credit facility also contains covenants requiring us to maintain:

- a maximum ratio of total funded debt to consolidated EBITDA (each as defined in the bank credit facility), measured quarterly on a rolling four-quarter basis, of 3.75 to 1 through March 31, 2004, declining to 3.5 to 1 beginning June 30, 2004, 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 $60 million, plus one-half of certain equity contribution proceeds received after December 31, 2002.

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

- failure to pay any principal, interest, fees, expenses or other amounts when due;
- failure to observe any agreement, obligation, or covenant in the credit agreement, subject to cure periods for certain failures;

- certain judgments against us or any of our subsidiaries, in excess of certain allowances;
- certain ERISA events involving us or our subsidiaries;
- cross defaults to certain material indebtedness;
- 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.

Senior Secured Notes. In June 2003, our operating partnership entered into a master shelf agreement with an institutional lender pursuant to which it issued $30.0 million aggregate principal amount of senior secured notes with an interest rate of 6.95% and a maturity of seven years. In July 2003, our operating partnership issued $10.0 million aggregate principal amount of senior secured notes pursuant to the master shelf agreement with an interest rate of 6.88% and a maturity of seven years.

The following is a summary of the material terms of the senior secured notes.

The notes represent senior secured obligations of our operating partnership and will rank at least *pari passu* in right of payment with the bank credit facility. The notes are secured, on an equal and ratable basis with the obligations of the operating partnership under the credit facility, 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 senior secured notes are guaranteed by our operating partnership's subsidiaries and us.

The senior secured notes are redeemable, at our operating partnership's option and subject to certain notice requirements, at a purchase price equal to 100% of the principal amount together with accrued interest, plus a make-whole amount determined in accordance with the master shelf agreement.

The master shelf agreement relating to the notes contains substantially the same covenants and events of default as the bank credit facility.

If an event of default resulting from bankruptcy or other insolvency events occurs, the senior secured notes will become immediately due and payable. If any other event of default occurs and is continuing, holders of more than 50.1% in principal amount of the outstanding notes may at any time declare all the notes then outstanding to be immediately due and payable. If an event of default relating to nonpayment of principal, make-whole amounts or interest occurs, any holder of outstanding notes affected by such event of default may declare all the notes held by such holder to be immediately due and payable.

The Partnership was in compliance with all debt covenants at December 31, 2002 and September 30, 2003, and expects to be in compliance with debt covenants for the next twelve months.

Intercreditor and Collateral Agency Agreement. In connection with the execution of the master shelf agreement in June 2003, the lenders under the bank credit facility and the initial purchasers of the senior secured notes entered into an Intercreditor and Collateral Agency Agreement, which was acknowledged and agreed to by our operating partnership and its subsidiaries. This agreement appointed Union Bank of California, N.A. to act as collateral agent and authorized Union Bank to execute various security documents on behalf of the lenders under the bank credit facility and the initial purchases of the senior secured notes. This agreement specifies various rights and obligations of lenders under the bank credit facility, holders of senior secured notes and the other parties thereto in respect of the collateral securing Crosstex Energy Services, L.P.'s obligations under the bank credit facility and the master shelf agreement.

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 nine months ended September 30, 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 ending after December 15, 2003. The Partnership is evaluating its ownership interests in joint ventures and limited partnerships that are currently accounted for using the equity method of accounting to determine whether FIN No. 46 will require the consolidation of any of these investments.

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*

The principal executive officer and principal financial officer of Crosstex Energy GP, LLC, the general partner of the Partnership's general partner, evaluated the effectiveness of the Partnership's disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, such principal executive officer and principal financial officer concluded that, the Partnership's disclosure controls and procedures as of the end of the period covered by this report have been designed and are functioning effectively to provide 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. Crosstex Energy GP, LLC and the Partnership believe that a controls system, no matter how well designed and operated, can not 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 a company have been detected.

No change in the Partnership's internal control over financial reporting occurred during the Partnership's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect the Partnership's internal control over financial reporting.

PART II—OTHER INFORMATION

Item 1. *Legal Proceedings*

None.

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

In September 2003, Crosstex Energy, L.P. issued 1,725,000 common units in a public offering. Crosstex Energy GP, L.P. contributed $1.3 million in cash to Crosstex Energy, L.P. in conjunction with the issuance in order to maintain its 2.0% general partner interest.

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

31.1	Rule 13a-14(a) Certification.
31.2	Rule 13a-14(a) Certification.
32.1	Section 906 Certification.
32.2	Section 906 Certification.

(b) Reports on Form 8-K

On July 11, 2003, Crosstex Energy, L.P. filed a Current Report on Form 8-K (dated as of June 30, 2003) relating to the acquisition of assets from Duke Energy Field Services L.P.

On August 7, 2003, Crosstex Energy, L.P. filed a Current Report on Form 8-K which included its press release as Exhibit 99.1 announcing its financial results for the quarter ended June 30, 2003.

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 13th day of November 2003.

CROSSTEX ENERGY, L.P.

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

By: Crosstex Energy GP, LLC,
its general partner

By: /s/ WILLIAM W. DAVIS

William W. Davis,
Senior Vice-President and Chief Financial Officer

QuickLinks

QuickLinks -- Click here to rapidly navigate through this document

EXHIBIT 31.1

CERTIFICATIONS

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

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

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

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

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

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

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

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

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

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

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

Date: November 13, 2003

/s/ BARRY E. DAVIS

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

QuickLinks

EXHIBIT 31.1

CERTIFICATIONS

QuickLinks -- Click here to rapidly navigate through this document

EXHIBIT 31.2

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

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

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

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

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

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

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

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

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

Date: November 13, 2003	/s/ WILLIAM W. DAVIS
	William W. Davis, Senior Vice President and Chief Financial Officer (principal financial and accounting officer)

QuickLinks

EXHIBIT 31.2

QuickLinks -- Click here to rapidly navigate through this document

EXHIBIT 32.1

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 quarter ended September 30, 2003, 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, to the best of my knowledge:

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

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

Date: November 13, 2003	/s/ BARRY E. DAVIS
	Barry E. Davis President and Chief Executive Officer (principal executive officer)

QuickLinks -- Click here to rapidly navigate through this document

EXHIBIT 32.2

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 quarter ended September 30, 2003, 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, to the best of my knowledge:

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

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

Date: November 13, 2003

/s/ WILLIAM W. DAVIS

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