Use these links to rapidly review the document
TABLE OF CONTENTS
INDEX TO FINANCIAL STATEMENTS

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

Form 10-K/A
Amendment No. 1

☒ **Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the fiscal year ended December 31, 2003**

OR

☐ **Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the transition period from to**

Commission file number: 000-50067

CROSSTEX ENERGY, L.P.

(Exact name of registrant as specified in its charter)

Delaware *(State of organization)*	**16-1616605** *(I.R.S. Employer Identification No.)*
2501 CEDAR SPRINGS, SUITE 600 **DALLAS, TEXAS** *(Address of principal executive offices)*	**75201** *(Zip Code)*

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

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

Title of Each Class	Name of Exchange on which Registered
None	Not applicable

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT:

Title of Class
Common Units Representing Limited Partnership Interests

Indicate by check mark whether registrant 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, and has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

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

The aggregate market value of the Common Units representing limited partner interests held by non-affiliates of the registrant was approximately $74,396,675 on June 30, 2003, based on $32.81 per unit, the closing price of the Common Units as reported on the NASDAQ National Market on such date.

At February 28, 2004, there were outstanding 4,358,000 Common Units and 4,667,000 Subordinated Units.

DOCUMENTS INCORPORATED BY REFERENCE: None.

CROSSTEX ENERGY, L.P.
FORM 10-K/A
INTRODUCTORY NOTE

This Amendment No. 1 to annual report on Form 10-K/A ("Form 10-K/A") is being filed to amend our annual report on Form 10-K for the year ended December 31, 2003, which was originally filed on March 10, 2004 ("Original Form 10-K"). Accordingly, pursuant to rule 12b-15 under the Securities Exchange Act of 1934, as amended, this Form 10-K/A contains the complete text of items 6, 7, 8 and 9A of Part II and item 15 of Part IV, as amended, as well as certain currently dated certifications. Unaffected items have not been repeated in this Amendment No. 1.

In July 2004, we determined that, due to clerical errors, certain reconciling items between the detail accounts receivable and accounts payable subledgers and the general ledger relating to 2002 had not been properly cleared. As a result of correcting these errors, we have restated our consolidated balance sheets as of December 31, 2002 and 2003, our consolidated statement of operations for the year ended December 31, 2002, our consolidated statements of changes in partners' equity for the years ended December 31, 2002 and 2003, our consolidated statement of comprehensive income for the year ended December 31, 2002 and our consolidated statement of cash flows for the year ended December 31, 2002. We have also restated our notes to consolidated financial statements as necessary to reflect the adjustments. The net effect of the adjustments resulted in a reduction in net income and comprehensive income for the year ended December 31, 2002 by $1.7 million and a reduction in partners' equity and working capital as of December 31, 2002 and 2003. Please read note 2 to the accompanying consolidated financial statements for a discussion of the adjustments.

This amendment does not reflect events occurring after the filing of the Original Form 10-K, and does not modify or update the disclosures therein in any way other than as required to reflect the adjustments described above. Such events include, among others, the events described in our quarterly report on Form 10-Q for the quarter ended March 31, 2004 and the events described in our current reports on Form 8-K filed after the filing of the Original Form 10-K. We will file with the Securities and Exchange Commission an amendment to our quarterly report on Form 10-Q for the quarter ended March 31, 2004 to reflect changes therein required as a consequence of the adjustments described above.

TABLE OF CONTENTS

DESCRIPTION

GLOSSARY OF TERMS

As generally used in the energy industry and in this document, the following terms have the following meanings:

/d = per day
Btu = British thermal units
Mcf = thousand cubic feet
MMBtu = million British thermal units
MMcf = million cubic feet

CROSSTEX ENERGY, L.P.

PART II

Item 6. *Selected Financial Data*

The following table sets forth selected historical financial and operating data of Crosstex Energy, L.P. and our predecessor, Crosstex Energy Services, Ltd., as of and for the dates and periods indicated. The selected historical financial data are derived from the audited financial statements of Crosstex Energy, L.P. or our predecessor, Crosstex Energy Services, Ltd. The investment in our predecessor by Yorktown Energy Partners IV, L.P. in May 2000 resulted in the dissolution of the predecessor partnership and the creation of a new partnership with the same organization, purpose, assets, and liabilities. Accordingly, the financial statements of our predecessor for 2000 are divided into the four months ended April 30, 2000 and the eight months ended December 31, 2000 because a new basis of accounting was established effective May 1, 2000 to give effect to the Yorktown transaction. In addition, the summary historical financial and operating data of Crosstex Energy Services, Ltd. include the results of operations of the Arkoma system beginning in September 2000, the Gulf Coast system beginning in September 2000, the CCNG system, which includes the Corpus Christi system, the Gregory gathering system and the Gregory processing plant, beginning in May 2001, the Vanderbilt system beginning in December 2002 and the DEFS assets beginning in June 2003.

The table should be read together with "Management's Discussion and Analysis of Financial Condition and Results of Operations."

	Crosstex Energy, L.P.				Crosstex Energy Services, Ltd.(2)	
	Year Ended December 31, 2003(1) (Restated)	Year Ended December 31, 2002(1) (Restated)	Year Ended December 31, 2001	Eight Months Ended December 31, 2000	Four Months Ended April 30, 2000	Year Ended December 31, 1999
	($ in thousands, except per unit amounts)					
Statement of Operations Data:						
Revenues:						
Midstream	$ 993,140	$ 437,432	$ 362,673	$ 88,008	$ 3,591	$ 7,896
Treating	20,523	14,817	24,353	17,392	5,947	9,770
Total revenues	1,013,663	452,249	387,026	105,400	9,538	17,666
Operating costs and expenses:						
Midstream purchased gas	946,412	414,244	344,755	83,672	2,746	5,154
Treating purchased gas	7,568	5,767	18,078	14,876	4,731	8,110
Operating expenses	17,692	11,409	7,761	1,796	544	986
General and administrative(3)	6,844	7,513	5,583	2,010	810	2,078
Stock based compensation	5,345	41	—	—	8,802	—
Impairments	—	4,175	2,873	—	—	538
(Profit) loss on energy trading contracts	(1,905)	(1,657)	3,714	(1,253)	(638)	(1,764)
Depreciation and amortization	13,268	7,745	6,101	2,261	522	1,286
Total operating costs and expenses	995,224	449,237	388,865	103,362	17,517	16,388
Operating income (loss)	18,439	3,012	(1,839)	2,038	(7,979)	1,278

Other income (expense):						
Interest expense, net	(3,392)	(2,717)	(2,253)	(530)	(79)	(638)
Other income (expense)	179	49	174	115	381	(138)
Total other income (expense)	(3,213)	(2,668)	(2,079)	(415)	302	(776)
Net income (loss)	$ 15,226	$ 344	($ 3,918)	$ 1,623	($ 7,677)	$ 502
Net income (loss) per limited partner unit—basic(4)	$ 1.78	$ 0.04	N/A	N/A	N/A	N/A
Net income (loss) per limited partner unit—diluted(4)	$ 1.75	$ 0.04	N/A	N/A	N/A	N/A
Distributions per limited partner unit(5)	$ 2.50	$ 0.056	N/A	N/A	N/A	N/A
Balance Sheet Data (at period end):						
Working capital surplus (deficit)	$ (4,572)	$ (10,330)	$ (2,254)	$ 5,861	$ (4,005)	$ (3,483)
Property and equipment, net	203,909	109,948	84,951	37,242	10,540	8,072
Total assets	366,050	233,185	168,376	201,268	45,051	36,497
Long-term debt	60,750	22,550	60,000	22,000	7,000	5,389
Partners' equity	154,610	88,158	41,155	40,354	3,608	3,242
Cash Flow Data:						
Net cash flow provided by (used in):						
Operating activities	$ 46,460	$ (5,672)	$ (10,244)	$ 7,741	$ 7,380	$ 1,404
Investing activities	(110,289)	(33,240)	(52,535)	(25,643)	(2,849)	(1,342)
Financing activities	62,687	39,868	44,476	36,557	198	(857)
Other Financial Data:						
Midstream gross margin	$ 46,728	$ 23,188	$ 17,918	$ 4,336	$ 845	$ 2,742
Treating gross margin	12,955	9,050	6,275	2,516	1,216	1,660
Total gross margin(6)	$ 59,683	$ 32,238	$ 24,193	$ 6,852	$ 2,061	$ 4,402
Operating Data:						
Pipeline throughput (MMBtu/d)	626,000	392,000	313,000	104,000	23,000	20,000
Natural gas processed (MMBtu/d)	132,000	86,000	61,000	16,000	31,000	23,000
Treating volumes (MMBtu/d)(7)	90,000	98,000	63,000	36,000	27,000	13,000

(1) Restated to reflect the correction of clerical errors that resulted in certain reconciling items relating to 2002 not being properly cleared. See Note 2 to the consolidated financial statements. The adjustments resulted in a reduction in net income for the year ended December 31, 2002 by $1.7 million and a reduction in partners' equity and working capital as of December 31, 2002 and 2003 by $1.7 million.

(2) Crosstex Energy Services, Ltd. is the predecessor to Crosstex Energy, L.P. Results of operations and balance sheet data prior to May 1, 2000 represent historical results of the predecessor to Crosstex Energy Services, Ltd. These results are not necessarily comparable to the results of Crosstex Energy Services, Ltd. subsequent to May 2000 due to the new basis of accounting.

(3) For the year ended December 31, 2003, the amount for which general partner is entitled to reimbursement from us for allocated general and administrative expenses is limited to $6.0 million. Such limitation does not apply to expenses incurred in connection with acquisitions or business development opportunities evaluated on our behalf.

(4) Net income (loss) per limited partner unit is not applicable for periods prior to our initial public offering. Net income per unit of $0.04 for the year ended December 31, 2002 represents allocation of our 2002 net income for the period from December 17, 2002 to December 31, 2002.

(5) 2003 distributions include fourth quarter of 2003 distributions of $0.75 per unit paid in February 2004 and 2002 distributions include fourth quarter of 2002 distributions of $0.056 per unit paid in February 2003.

(6) Gross margin is defined as revenue less related cost of purchased gas.

(7) Represent volumes for treating plants operated by us whereby we receive a fee based on the volumes treated.

Item 7. *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.

Restatement

In July 2004, we determined that, due to clerical errors, certain reconciling items between the detail accounts receivable and accounts payable subledgers and the general ledger relating to 2002 had not been properly cleared. As a result of these errors and as more fully discussed in the Introductory Note to this Amendment No. 1, certain financial and other information contained herein has been restated to reflect adjustments described in Note 2 to the accompanying consolidated financial statements. Please read Note 2 for a discussion of the adjustments.

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 year ended December 31, 2003, 78% of our gross margin was generated in the Midstream division, with the balance in the Treating division, and approximately 71% of our gross margin was generated in the Texas Gulf Coast region. We focus on gross margin to manage our business because our business is generally to gather, process, transport, market or treat gas for a fee or a buy-sell margin. We buy and sell most of our gas at a fixed relationship to the relevant index price so our margins are not significantly affected by changes in gas prices. As explained under "Commodity Price Risk" below, we enter into financial instruments to reduce volatility in our gross margin due to price fluctuations.

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 December 31, 2003, we have invested approximately $222.0 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;

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

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, and, if we are to be profitable, at a smaller discount or larger premium to the index than it was purchased. We attempt to execute all purchases and sales substantially concurrently, or we enter into a future delivery obligation, thereby establishing the basis for the margin we will receive for each natural gas transaction. Our gathering and transportation margins related to a percentage of the index price can be adversely affected by declines in the price of natural gas. See "Commodity Price Risk" below for a discussion of how we manage our business to reduce the impact of price volatility.

We generate producer services revenues through the purchase and resale of natural gas. 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 engage in such activities on more than 20 interstate and intrastate pipelines with a major emphasis on Gulf Coast pipelines. We focus on supply aggregation transactions in which we either purchase and resell gas and thereby eliminate the need of the producer to engage in the marketing activities typically handled by in-house marketing or supply departments of larger companies, or act as agent for the producer.

We generate treating revenues under three arrangements:

- a volumetric fee based on the amount of gas treated, which accounted for approximately 55% and 66% of the operating income in our Treating division for the years ended December 31, 2003 and 2002, respectively;
- a fixed fee for operating the plant for a certain period, which accounted for approximately 38% and 22% of the operating income in our Treating division for the years ended December 31, 2003 and 2002, respectively; or
- a fee arrangement in which the producer operates the plant, which accounted for approximately 7% and 12% of the operating income in our Treating division for the years ended December 31, 2003 and 2002, respectively.

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 ended in December 2003, the amount which we reimbursed our general partner and its affiliates for costs incurred with respect to the general and administrative services performed on our behalf could not exceed $6.0 million. This reimbursement cap did 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. This cap expired in December 2003.

Crosstex Energy, Inc. modified certain terms of certain outstanding options in the first quarter of 2003 which allowed the option holders to elect to be paid in cash for the modified options based on the fair value of the options. These modifications resulted in variable award accounting for the modified options until the option holders elect to cash out the options or the election to cash out the options lapses. CEI is responsible for paying the intrinsic value of the options for the holders who elect to cash out their options. December 31, 2003 was the last valuation date that a holder of modified options could elect the cash-out alternative. Accordingly, effective January 1, 2004, the remaining modified options will be accounted for as fixed options. We recognized total compensation expense of approximately $5.0 million related to these modified options, which has been recorded by the Partnership as non-cash stock based compensation expense in the year ended December 31, 2003.

We have grown significantly through asset purchases in recent years, which creates many of the major differences when comparing operating results from one period to another. The most significant asset purchases are the acquisitions of our CCNG system, Vanderbilt system and DEFS assets.

We acquired the CCNG system in May 2001 for a purchase price of approximately $30.0 million. The CCNG system included four principal assets: the Corpus Christi system, the Gregory gathering system, the Gregory processing plant and the Rosita treating plant.

- The Corpus Christi system consists of approximately 295 miles of gathering and transmission lines extending from supply points in south Texas to markets in Corpus Christi Texas, with average throughput of approximately 152,000 MMBtu of gas per day at the time of the acquisition.

- The Gregory gathering system consists of approximately 297 miles of gathering lines located primarily in the Corpus Christi Bay area, with average throughput of approximately 76,500 MMBtu of gas per day at the time of the acquisition.

- The Gregory processing plant processes most of the gas gathered by the Gregory gathering system, extracting the liquids, fractionating them into NGLs, and selling the remaining residue gas. At the time of the acquisition, the plant was processing approximately 43,400 MMBtu of gas per day.

- The Rosita treating plant was treating approximately 25,000 MMBtu of gas per day at the time of its acquisition. The Rosita treating plant is operated in the Partnership's Treating

Division, whereas all of the other assets in the CCNG acquisition are included in the Partnership's Midstream Division.

We acquired the Vanderbilt system in December 2002 for a purchase price of $12.0 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 DEFS assets in June 2003 for $68.1 million in cash. The principal assets acquired were the Mississippi pipeline system, a 638-mile natural gas gathering and transmission system in south central Mississippi that serves utility and industrial customers, and a 12.4% non-operating interest in the Seminole gas processing plant, which provides carbon dioxide separation and sulfur removal services for several major oil companies in West Texas. The acquisition provided us with a new core area for growth in south central Mississippi, expanded our presence in West Texas, increased the total miles of our pipelines from 1,700 to 2,500 and enabled us to enter the business of carbon dioxide separation.

Commodity Price Risk

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 8.4% in 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, the changes are equal and offsetting.

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 year ended December 31, 2003. Our gathering and transportation margins related to a percentage of the index price can be adversely affected by declines in the price of natural gas.

Asset or Business	Year ended December 31, 2003 Gas Purchased Fixed Amount to Index	Gas Purchased Percentage of Index	Gas Sold Fixed Amount to Index	Gas Sold Percentage of Index
	(in billions of MMBtus)			
Gulf Coast system	28.5	2.5	31.1	—
CCNG transmission system	59.5	0.7	60.2	—
Gregory gathering system(1)	52.5	2.5	45.8	—
Vanderbilt system(1)	10.2	12.4	20.0	—
Conroe system(1)	0.1	0.3	0.3	
Arkoma gathering system	0.3	4.4	4.7	—
Mississippi system	13.5	0.5	14.0	
Producer services(2)	94.2	0.4	94.6	—

(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.

We estimate that, due to the gas that we purchase at a percentage of index price, for each $0.50 per MMBtu increase or decrease in the price of natural gas, our gross margins increase or decrease by approximately $0.7 million on an annual basis (before consideration of the hedges discussed below). As of December 31, 2003, we have hedged a portion of our exposure to such fluctuations in natural gas prices as follows for future periods:

Period	Volume Hedged (MMBtu per month)	Weighted-Average Price per MMBtu
1st quarter of 2004	90,000	$ 5.11
2nd quarter of 2004	70,000	4.97
3rd quarter of 2004	30,000	4.85
4th quarter of 2004	30,000	4.85

We expect to continue to hedge our exposure to gas production which we purchase at a percentage of index when market opportunities appear attractive.

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 year ended December 31, 2003, we purchased approximately 16% 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 MMcf/d, 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 year ended December 31, 2003, we purchased approximately 84% 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.

Our Conroe gas plant and gathering system generates revenues based on fees it charges to producers for gathering and compression services, and we retain 40% of the NGLs produced from a portion of the gas processed at the facility.

We own an undivided 12.4% interest in the Seminole gas processing plant, which is located in Gaines County, Texas. The Seminole plant has dedicated long-term reserves from the Seminole San Andres unit, to which it also supplies carbon dioxide under a long-term arrangement. Revenues at the plant are derived from a fee it charges producers, including those at the Seminole San Andres unit, for each Mcf of carbon dioxide returned to the producer for reinjection. The fees currently average approximately $0.59 for each Mcf of carbon dioxide returned. Reinjected carbon dioxide is used in a tertiary oil recovery process in the field. The plant also receives 50% of the NGLs produced by the plant. Therefore, we have commodity price exposure due to variances in the prices of NGLs. In the last half of 2003, our share of NGLs totaled 2,824,000 gallons at an average price of $0.5154 per gallon. We have entered into a one-year contract with Duke Energy NGL Services, L.P. to market our NGLs on our behalf, and receive our share of proceeds from the sale of carbon dioxide from the plant operator. We are separately billed by the plant operator for our share of expenses.

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.

	Year Ended December 31, 2003	2002 (Restated)	2001
	(dollars in millions)		
Midstream revenues	$ 993.1	$ 437.4	$ 362.7
Midstream purchased gas	946.4	414.2	344.8
Midstream gross margin	46.7	23.2	17.9
Treating revenues	20.5	14.8	24.4
Treating purchased gas	7.5	5.8	18.1
Treating gross margin	13.0	9.0	6.3
Total gross margin	$ 59.7	$ 32.2	$ 24.2
Midstream Volumes (MMBtu/d):			
Gathering and transportation	626,000	392,000	313,000
Processing	132,000	86,000	61,000
Producer services	259,000	230,000	283,000
Treating Volumes (MMBtu/d)	90,000	98,000	63,000

Year Ended December 31, 2003 Compared to Year Ended December 31, 2002

Gross Margin. Midstream gross margin was $46.7 million for the year ended December 31, 2003 compared to $23.2 million (restated) for the year ended December 31, 2002, an increase of $23.5 million, or 101%. The largest increase in gross margin was due to the acquisition of assets from Duke Energy Field Services on June 30, 2003. These assets added gross margin of $9.4 million. The CCNG system had significant growth due to an increase in on-system volume and the addition of the Hallmark lateral, resulting in an increase in margin of $4.7 million. We acquired the Vanderbilt Gathering system on December 31, 2002; this system added gross margin of $4.4 million. Gregory gathering system and Gregory processing plant had increased margin of $2.6 million. These systems had significant growth in volume due to producer drilling activity in the area, to which we responded with the Gregory plant expansion during 2003. The Gulf Coast system had increased margin of $1.2 million despite the fact that volumes declined. The reason for the decline in volumes was because we sourced two markets from Vanderbilt the last half of 2003 that were previously sourced from the Gulf Coast system. We had an increase in volume and increase in margin due to a large customer taking gas from our system for 12 months in 2003 and only 6 months in 2002, and we had increased margin due to renegotiation of producer contracts. The Arkoma system also had increased volume, creating an increase in margin of $0.8 million.

Treating gross margin was $13.0 million for the year ended December 31, 2003 compared to $9.0 million in the same period in 2002, an increase of $4.0 million, or 44%. The increase was due to 27 new plants placed in service in 2003, which generated $3.7 million offset by 10 plants removed from service in 2003, which decreased margin by $0.8 million (a net increase of $2.9 million). In addition, an increase in volume at two plants with throughput-based contracts accounted for $1.1 million of the increase in treating margin.

Operating Expenses. Operating expenses were $17.7 million for the year ended December 31, 2003, compared to $11.4 million for the year ended December 31, 2002, an increase of $6.3 million, or 55%. An increase of $3.1 million was associated with the acquisition of assets from Duke Energy Field Services in June 2003. Costs for our technical services support increased by approximately $0.8 million due to staff additions to operate the assets acquired in December 2002 and in June 2003 from DEFS and to manage other construction projects. The Vanderbilt system added $1.1 million to operating expenses, new treating plants increased operating expenses by $0.6 million and the Gregory Plant expansion added $0.4 million in operating expenses.

General and Administrative Expenses. General and administrative expenses were $6.8 million for the year ended December 31, 2003 compared to $7.5 million for the year ended December 31, 2002, a decrease of $0.7 million, or 9%. The decrease was due to the general and administrative expense limit set by our partnership agreement for the year of 2003, which resulted in general and administrative expenses in excess of specified levels being reimbursed by the general partner. Had the cap not been in place, general and administrative expenses would have been $10.2 million, or an increase of $2.7 million. The increase was primarily due to increases in staffing associated with the requirements of the Duke Energy Field Services acquisition and associated with being a public entity.

Impairments. We had no impairment expense in 2003 compared to $4.2 million in 2002. See "Year Ended December 31, 2002 Compared to Year Ended December 31, 2001" for a discussion of the 2002 charge.

(Profit) Loss on Energy Trading Activities. The profit on energy trading activities was $1.9 million for the year ended December 31, 2003 compared to $1.7 million (restated) for the year ended December 31, 2002, an increase of $0.2 million, or 12%. Included in these amounts are realized margins on delivered volumes in the producer services "off-system" gas marketing operations of $2.2 million in 2003 and $1.8 million in 2002, an increase of $0.4 million, or 22%. This increase is primarily due to an increase in our producer services volumes. In addition, losses of $0.3 million and $0.1 million (restated) relating primarily to options bought and/or sold in the management of the company's Enron position were booked in 2003 and 2002, respectively.

Depreciation and Amortization. Depreciation and amortization expenses were $13.3 million for the year ended December 31, 2003 compared to $7.7 million for the year ended December 31, 2002, an increase of $5.5 million, or 71%. The increase related to the Duke assets purchased in June 2003 was $2.3 million. The Vanderbilt system, purchased in December 2002 added $1.0 million of depreciation, new treating plants placed in service in 2003 resulted in an increase of $0.9 million and the Hallmark system added $0.3 million. The remaining $1.0 million increase in depreciation and amortization is a result of expansion projects and other new assets, such as the expansion of the Gregory Plant.

Interest Expense. Interest expense was $3.4 million for the year ended December 31, 2003 compared to $2.7 million for the year ended December 31, 2002, an increase of $0.7 million, or 25%. The increase relates primarily to bank debt incurred in the acquisition of the Duke assets in June, 2003 and by higher interest rates (weighted average rate of 5.35% in 2003 compared to 4.67% in 2002).

Net Income (Loss). Net income for the year ended December 31, 2003 was $15.2 million compared to $0.3 million (restated) for the year ended December 31, 2002, an increase of $14.9 million. This was generally the result of the increase in gross margin of $27.5 million from

2002 to 2003, offset by increases in ongoing cash costs for operating expenses and interest expense as discussed above. Non-cash charges for depreciation and amortization expenses and stock based compensation also increased.

Year Ended December 31, 2002 Compared to Year Ended December 31, 2001

Gross Margin. Midstream gross margin was $23.2 million (restated) for the year ended December 31, 2002 compared to $17.9 million for the year ended December 31, 2001, an increase of $5.3 million, or 30%. The Corpus Christi system, the Gregory gathering system and the Gregory processing plant were acquired in May 2001. The gross margin from these assets for the 12-month period of 2002 exceeded that of the 8-month period in 2001 by $6.9 million. This was offset by lower margin of $0.8 million at the Arkoma system and $0.4 million at the Gulf Coast system due to lower prices in 2002.

Treating gross margin was $9.0 million for the year ended December 31, 2002 compared to $6.3 million for the same period in 2001, an increase of $2.7 million, or 43%. The increase was primarily due to 14 new plants placed in service in 2002, which generated $1.6 million. In addition, margin of $1.0 million was generated at two plants due to increased volume and additional margin of $0.9 million from six plants in service the entire year 2002, but were in operation only a few months in 2001. This was offset by $0.3 million decrease in margin from four plants being removed from service and another $0.3 million from contract restructuring at one treating facility.

Operating Expenses. Operating expenses were $11.4 million for the year ended December 31, 2002, compared to $7.8 million for the year ended December 31, 2001, an increase of $3.0 million, or 47%. $1.8 million of the increase was associated with the CCNG assets purchased in May 2001 and another $1.0 million was associated with growth in the treating division.

General and Administrative Expenses. General and administrative expenses were $7.5 million for the year ended December 31, 2002 compared to $5.6 million for the year ended December 31, 2001, an increase of $1.9 million, or 35%. The increases were associated with increases in staffing associated with the requirements of the CCNG assets and in preparation for our initial public offering.

Impairments. Impairment expense was $4.2 million in 2002 compared to $2.9 million in 2001. 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 2002 and 2001 are associated with writing off certain of these intangible contract values. The charges in 2001 relate to intangible contract values associated with the Jonesville processing plant, which was transferred out of the partnership in conjunction with the initial public offering. Impairment charges in 2002 are primarily associated with intangible contract values at 4 specific treating plants. Two of the plants are still working at the location where they were sited at the time of the Yorktown investment, but had experienced recent declines in cash flows. As the operator of the wells behind these plants had recently told the company that it was canceling its drilling plans in the area, the declines are expected to continue until the plants are relocated. The other two treating plants were removed from service during 2002 at the locations where they were sited at the time of the Yorktown investment, and therefore the intangible contract values associated with that particular location were deemed impaired. (One of the plants was immediately contracted at another location at a higher rental rate than previously in effect. The other plant is currently in inventory.)

(Profit) Loss on Energy Trading Activities. The profit on energy trading activities was $1.7 million (restated) for the year ended December 31, 2002 compared to a loss of $3.7 million for the year ended December 31, 2001, an increase of $5.4 million. Included in these amounts are realized margins on delivered volumes in the producer services "off-system" gas marketing operations of $1.8 million in 2002 and $1.9 million in 2001. This variance is primarily due to the $5.7 million reserve booked in 2001 against the company's Enron receivable due to Enron Corporation's December 2001 bankruptcy.

Depreciation and Amortization. Depreciation and amortization expenses were $7.7 million for the year ended December 31, 2002 compared to $6.1 million for the year ended December 31, 2001, an increase of $1.6 million, or 27%. The increase is primarily related to additional depreciation expense associated with the CCNG assets purchased in May 2001, partially offset by a decrease in amortization expense due to goodwill no longer being amortized in 2002 in accordance with SFAS 142.

Interest Expense. Interest expense was $2.7 million for the year ended December 31, 2002 compared to $2.3 million for the year ended December 31, 2001, an increase of $0.4 million, or 21%. The increase relates primarily to bank debt incurred in the acquisitions of the CCNG assets in May 2001, offset by lower interest rates.

Net Income (Loss). Net income (loss) for the year ended December 31, 2002 was $0.3 million (restated) compared to ($3.9) million for the year ended December 31, 2001, an increase of $4.2 million. Gross margin increased by $8.0 million from 2001 to 2002, offset by increases in ongoing cash costs for operating expenses, general and administrative expenses, and interest expense as discussed above. Non-cash charges for depreciation and amortization expenses and for impairment expense also increased, offset by the gain on energy trading activities.

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 Combined Financial Statements.

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-basis accounting rather than mark-to-market accounting unless the contracts meet the requirements of a derivative under SFAS No. 133. Our energy trading contracts qualify as derivatives, and accordingly, we continue to use mark-to-market accounting for both physical and financial contracts of our producer services business. Accordingly, any gain or loss associated with changes in the fair value of derivatives and physical delivery contracts relating to our producer services natural gas marketing activities are recognized in earnings as profit or loss on energy trading contracts immediately.

For each reporting period, we record the fair value of open energy trading contracts based on the difference between the quoted market price and the contract price. Accordingly, the change in fair value from the previous period in addition to the realized gains or losses on settled activities are reported as profit or loss on energy trading activities 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 $46.5 million for the year ended December 31, 2003 compared to cash used by operations of $5.7 million for the year ended December 31, 2002. Income before non-cash income and expenses was $33.6 million in 2003 and $12.3 million (restated) in 2002. Changes in working capital provided $12.8 million in cash flows from operating activities in 2003 and used $18.0 million (restated) in cash flows from operating activities in 2002. Income before non-cash income and expenses increased between years primarily due to asset acquisitions as discussed in "Results of Operations—Year Ended December 31, 2003 compared to year ended December 31, 2002." Changes in working capital provided $12.8 million in cash flows in 2003 primarily due to $3.5 million in prepayments by certain customers in December 2003 combined with $3.8 million due to delays in collecting from a few large customers in December 2002 until January 2003. In addition, property cost accruals increased by approximately $1.5 million due to an increase in capital projects late in 2003 as compared to 2002. The remaining changes in working capital were due to timing of receipts and disbursements in the ordinary course of business.

Net cash used in investing activities was $110.3 million and $33.2 million for the year ended December 31, 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 and the acquisitions of the Vanderbilt system ($12.0 million) and the Hallmark Lateral ($2.3 million). The primary internal growth projects referred to during 2003 were the Gregory plant expansion ($7.4 million), improvements to the Vanderbilt system ($4.7 million), and buying, refurbishing and installing treating plants ($9.9 million). The main projects in the 2002 period were the acquisition and connection of the Hallmark system ($4.3 million), the Calpine interconnect ($1.1 million), buying, refurbishing and installing treating plants ($7.3 million), and a line extension at the Gregory plant ($0.9 million).

Net cash provided by (used in) financing activities was $62.7 million and $39.9 million for the years ended December 31, 2003 and 2002, respectively. Financing activities in 2003 relate principally to the funding of the Duke assets acquisition and internal growth projects discussed above from bank borrowings and proceeds from the sale of common units discussed below. Financing activities during 2002 primarily represented funding or refunding of the partnership's debt and working capital needs through bank borrowings and net proceeds from our initial public offering in December 2002 and partner contributions. Financing activities also included a decrease in drafts payable of $17.1 million for the year ended December 31, 2003 and an increase in drafts payable of $25.6 million for the year ended December 31, 2002. In order to reduce our interest costs, we borrow money to fund outstanding checks as they are presented to the bank. Fluctuations in drafts payable are caused by timing of disbursements, cash receipts and draws on our revolving credit facility.

Off-Balance Sheet Arrangements. We had no off-balance sheet arrangements as of December 31, 2003 and 2002.

September 2003 Sale of Common Units. In September 2003, we completed a public offering of 1,725,000 common units at a public offering price of $35.97 per common unit. We received net proceeds of approximately $59.1 million, including an approximate $1.3 million capital contribution by our 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.

We believe that cash generated from operations will be sufficient to meet our present quarterly distribution level of $0.75 per quarter and to fund a portion of our anticipated capital expenditures through December 31, 2004. We expect to fund the remaining capital expenditures from the proceeds of borrowings under the revolving credit facility discussed below. Total capital expenditures are budgeted to be approximately $17 million in 2004. Our ability to pay distributions to our unit holders and to fund planned capital expenditures and to make acquisitions will depend upon our future operating performance, which will be affected by prevailing economic conditions in our industry and financial, business and other factors, some of which are beyond our control.

Subsequent Event. We entered into a definitive agreement on February 13, 2004 for the acquisition of the LIG Pipeline Company and its subsidiaries (LIG) from American Electric Power for $76.2 million. The acquisition will increase our pipeline miles by approximately 2,000 miles, to a total of 4,500 pipeline miles, and increase pipeline throughput by approximately 600,000 MMBtu/d. The closing, which is subject to completion of certain conditions, is expected to occur within 90 days of the date of the definitive agreement. We will finance the acquisition through borrowings under our existing bank credit facility, issuance of additional senior notes or other financing alternatives.

Total Contractual Cash Obligations. A summary of our total contractual cash obligations as of December 31, 2003, is as follows:

	Payments due by period					
Contractual Obligations	**Total**	**2004**	**2005**	**2006**	**2007-2008**	**Thereafter**
	(in millions)					
Long-Term Debt	$ 60.8	$ .1	$ .1	$ 28.8	$ 19.4	$ 12.4
Capital Lease Obligations	—	—	—	—	—	—
Operating Leases	$ 5.6	$ 1.2	$ 1.1	$ 1.0	$ 1.4	$ .9
Unconditional Purchase Obligations	—	—	—	—	—	—
Other Long-Term Obligations	—	—	—	—	—	—
Total Contractual Obligations	$ 66.4	$ 1.3	$ 1.2	$ 29.8	$ 20.8	$ 13.3

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

Other Obligations. We receive notices from various pipeline companies from time to time of gas volume allocation corrections related to gas deliveries on their pipeline systems. Since we balance our purchases and sales in the pipelines, these allocation corrections normally have little impact to our gross margin since both the purchase and sale on the pipeline system require corrections. At December 31, 2003, we had a dispute related to one such allocation correction with a pipeline company and a customer on that pipeline. In reallocating previous settled deliveries, the pipeline company has billed us for approximately $1.2 million of gas deliveries, which occurred in the period from December 2000 through February 2001. We have, in turn, billed our customer who was over paid due to the allocation error. Our customer is disputing the timeliness of this corrected billing. The allocation error occurred prior to the acquisition by us of the subsidiary involved in the dispute. We have an indemnity from the seller for liabilities prior to the acquisition date. As of December 31, 2003, we have recorded a receivable of $1.2 million in other current receivables and a liability of $1.2 million in other current liabilities related to this allocation correction. We believe the dispute of the receivable by our customer is without merit, and further believe that we are protected against loss by our potential indemnity claim

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. At December 31, 2003, $20.0 million was outstanding under the acquisition facility, leaving approximately $50.0 available for future borrowings. 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 re-borrowed.

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 December 31, 2003 we had $30.3 million of letters of credit issued under the $50 million working capital and letter of credit facility, leaving approximately $19.7 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 $25.0 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 re-borrowed. We are 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 Operating Partnership was in compliance with all debt covenants at December 31, 2003 and 2002.

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 and Significant Customers

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.

During the year ended December 31, 2003, we had one customer that individually accounted for more than 10% of consolidated revenues. During the year ended December 31, 2003, Kinder Morgan Tejas accounted for 20.5% of our consolidated revenue. While this customer represents a significant percentage of consolidated revenues, the loss of this customer would not have material impact on our results of operations.

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 years ended December 31, 2001, 2002, or 2003. 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. For a more complete discussion of the environmental laws and regulations that impact us. See Item 1. "Business—Environmental Matters."

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 was adopted by us on January 1, 2003. We do not presently have any significant legal asset retirement obligations, and accordingly, the adoption of SFAS No. 143 had no impact on our results of operations or financial condition.

SFAS No 148, *Accounting for Stock-Based Compensation—Transition and Disclosure, an amendment of FASB Statement No. 123*, SFAS No. 148 amends SFAS No. 123 and provides alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. SFAS No. 148 also requires prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based compensation and the effect of the method used on reported results. SFAS No. 148 permits two additional transition methods for entities that adopt the fair value based method, these methods allow companies to avoid the ramp-up effect arising from prospective application of the fair value based method. This Statement is effective for financial statements for fiscal years ending after December 15, 2002. We have complied with the disclosure provisions of the Statement in our financial statements.

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 ended after December 15, 2002. The adoption of this statement had no impact on our results of operations or financial condition.

In January 2003, the FASB issued FASB Interpretation No. 46, *Consolidation of Variable Interest Entities*, *an interpretation of ARB No 51*. In December 2003, the FASB issued FIN No. 46R which clarified certain issues identified in FIN 46. FIN No. 46R requires an entity to consolidate a variable interest entity if it is designated as the primary beneficiary of that entity even if the entity does not have a majority of voting interests. A variable interest entity is generally defined as an entity where its equity is unable to finance its activities or where the owners of the entity lack the risk and rewards of ownership. The provisions of this statement apply at inception for any entity created after January 31, 2003. For an entity created before February 1, 2003, the provisions of this interpretation must be applied at the beginning of the first interim or annual period beginning after March 15, 2004. We are currently evaluating our ownership interests in joint ventures and limited partnerships that are currently accounted for using the equity method of accounting to determine whether FIN No. 46R will require the consolidation of any of these investments, however, we currently believe that one of our joint venture interests, as described in Note 4 to the financial statements, will be consolidated in our financial statements when FIN No. 46R is adopted in March 2004.

The FASB issued Statement of Financial Accounting Standards No. 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity," ("SFAS No. 150") in May 2003. SFAS No. 150 establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. We have no financial instruments which are subject to SFAS No. 150.

Disclosure Regarding Forward-Looking Statements

This report on Form 10-K/A includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 31E of the Securities Exchange Act of 1934, as amended. 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), including, without limitation, the information set forth in "Management's Discussion and Analysis of Financial Condition and Results of Operations," are forward-looking statements. These statements can be identified by the use of forward-looking terminology including "forecast," "may," "believe," "will," "expect," "anticipate," "estimate," "continue" or other similar words. These statements discuss future expectations, contain projections of results of operations or of financial condition or state other "forward-looking" information. In addition to specific uncertainties discussed elsewhere in this Form 10-K, the following risks and uncertainties may affect our performance and results of operations:

- we may not have sufficient cash after the establishment of cash reserves and payment of our general partner's fees and expenses to pay the minimum quarterly distribution each quarter;
- if we are unable to contract for new natural gas supplies, we will be unable to maintain or increase the throughput levels in our natural gas gathering systems and asset utilization rates at our treating and processing plants to offset the natural decline in reserves;
- our profitability is dependent upon the prices and market demand for natural gas and NGLs, which are beyond our control and have been volatile;
- our future success will depend in part on our ability to make acquisitions of assets and businesses at attractive prices and to integrate and operate the acquired business profitably;
- Crosstex Energy, Inc. owns approximately 55% aggregate limited partner interest of us and it owns and controls our general partner, thereby effectively controlling all limited partnership decisions; conflicts of interest may arise in the future between Crosstex Energy, Inc. and its affiliates, including our general partner, and our partnership or any of our unitholders;
- since we are not the operator of certain of our assets, the success of the activities conducted at such assets are outside our control;
- we operate in very competitive markets and encounter significant competition for natural gas supplies and markets;
- we are subject to risk of loss resulting from nonpayment or nonperformance by our customers or counterparties;
- we may not be able to retain existing customers, especially key customers, or acquire new customers at rates sufficient to maintain our current revenues and cash flows;
- the construction of gathering, processing and treating facilities requires the expenditure of significant amounts of capital and subjects us to construction risks and risks that natural gas supplies will not be available upon completion of the facilities;

- our business is subject to many hazards and operational risks, some of which may not be covered by insurance; and
- we are subject to extensive and changing federal, state and local laws and regulations designed to protect the environment, and these laws and regulations could impose liability for remediation costs and civil or criminal penalties for non-compliance.

Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual results may differ materially from those in the forward-looking statements. We disclaim any intention or obligation to update or review any forward-looking statements or information, whether as a result of new information, future events or otherwise.

Except as required by applicable securities laws, we do not intend to update these forward-looking statements and information.

Item 8. *Financial Statements and Supplementary Data*

The Report of Independent Registered Public Accounting Firm, Consolidated Financial Statements and supplementary financial data required by this Item are set forth on pages F-1 through F-42 and S-1 of this Report and are incorporated herein by reference.

Item 9A. *Controls And Procedures*

We carried out an evaluation, under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer of Crosstex Energy GP, LLC, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that, to the extent and in the case described in the following paragraph, our disclosure controls and procedures were not effective as of December 31, 2003 to provide reasonable assurance that information required to be disclosed in our reports filed or submitted under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms.

In July 2004, we determined during the course of internal reviews that, due to clerical errors, certain reconciling items between the detail accounts receivable and accounts payable subledgers and the general ledger relating to 2002 had not been properly cleared. We identified these errors and promptly brought them to the attention of our audit committee and auditors. As a result of correcting these errors, in this annual report on Form 10-K/A, we have restated our consolidated balance sheets as of December 31, 2002 and 2003, our consolidated statement of operations for the year ended December 31, 2002, our consolidated statements of changes in partners' equity for the years ended December 31, 2002 and 2003, our consolidated statement of comprehensive income for the year ended December 31, 2002 and our consolidated statement of cash flows for the year ended December 31, 2002. We have also restated our notes to consolidated financial statements as necessary to reflect the adjustments. These errors resulted from a deficiency in the procedures to reconcile the detail accounts receivable and accounts payable subledgers to the general ledger. Our independent auditors, KPMG LLP, have reviewed these matters and advised our Audit Committee that the deficiency constituted a material weakness as defined in Statements of Auditing Standards No. 60. In light of the discovery of these errors, we have implemented new procedures for reconciling subledgers to the general ledger and disposition and resolution of reconciling items on a timely basis. Management believes that controls are now in place to ensure that similar errors do not occur again.

There have been no changes in our internal controls over financial reporting that occurred during the three months ended December 31, 2003 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

PART IV

Item 15. *Exhibits, Financial Statement Schedules and Reports on Form 8-K*

(a) Financial Statements and Schedules

(1) See the Index to Financial Statements on page F-1.

(2) See Schedule II—Valuation and Qualifying Accounts on Page S-1.

(3) Exhibits

The exhibits filed as part of this report are as follows (exhibits incorporated by reference are set forth with the name of the registrant, the type of report and registration number or last date of the period for which it was filed, and the exhibit number in such filing):

Number		Description
3.1	—	Certificate of Limited Partnership of Crosstex Energy, L.P. (incorporated by reference to Exhibit 3.1 to our Registration Statement on Form S-1, file No. 333-97779).
3.2	—	Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of December 17, 2002 (incorporated by reference to Exhibit 3.4 to our Annual Report on Form 10-K for the year ended December 31, 2002).
3.3	—	Certificate of Limited Partnership of Crosstex Energy Services, L.P. (incorporated by reference to Exhibit 3.3 to our Registration Statement on Form S-1, file No. 333-97779).
3.4	—	Amended and Restated Agreement of Limited Partnership of Crosstex Energy Services, L.P., dated as of December 17, 2002 (incorporated by reference to Exhibit 3.4 to our Annual Report on Form 10-K for the year ended December 31, 2002).
3.5	—	Certificate of Limited Partnership of Crosstex Energy GP, L.P. (incorporated by reference to Exhibit 3.5 to our Registration Statement on Form S-1, file No. 333-97779).
3.6	—	Agreement of Limited Partnership of Crosstex Energy GP, L.P., dated as of July 12, 2002 (incorporated by reference to Exhibit 3.6 to our Registration Statement on Form S-1, file No. 333-97779).
3.7	—	Certificate of Formation of Crosstex Energy GP, LLC (incorporated by reference to Exhibit 3.7 to our Registration Statement on Form S-1, file No. 333-97779).
3.8	—	Amended and Restated Limited Liability Company Agreement of Crosstex Energy GP, LLC, dated as of December 17, 2002 (incorporated by reference to Exhibit 3.8 to our Registration Statement on Form S-1, File No. 333-106927).
4.1	—	Specimen Unit Certificate for Common Units (incorporated by reference to Exhibit 4.1 to our Registration Statement on Form S-1, file No. 333-97779).
10.1	—	Second Amended and Restated Credit Agreement, dated November 26, 2002, among Crosstex Energy Services, L.P., Union Bank of California, N.A. and certain other parties (incorporated by reference to Exhibit 10.1 to our Annual Report on Form 10-K for the year ended December 31, 2002).

10.2	—	First Amendment to Second Amended and Restated Credit Agreement, dated as of June 3, 2003, among Crosstex Energy Services, L.P., Union Bank of California, N.A. and certain other parties (incorporated by reference to Exhibit 10.2 to our Registration Statement on Form S-1, File No. 333-106927).
10.3*	—	Second Amendment to Second Amended and Restated Credit Agreement, dated as of June 3, 2003, among Crosstex Energy Services, L.P., Union Bank of California, N.A. and certain other parties.
10.4	—	$50,000,000 Senior Secured Notes Master Shelf Agreement, dated as of June 3, 2003 (incorporated by reference to Exhibit 10.3 to our Registration Statement on Form S-1, Form No. 333-106927).
10.5	—	First Contribution, Conveyance and Assumption Agreement, dated November 27, 2002, among Crosstex Energy, L.P. and certain other parties (incorporated by reference to Exhibit 10.2 to our Annual Report on Form 10-K for the year ended December 31, 2002).
10.6	—	Closing Contribution, Conveyance and Assumption Agreement, dated December 11, 2002, among Crosstex Energy, L.P. and certain other parties (incorporated by reference to Exhibit 10.3 to our Annual Report on Form 10-K for the year ended December 31, 2002).
10.7+	—	Crosstex Energy GP, LLC Long-Term Incentive Plan, dated July 12, 2002 (incorporated by reference to Exhibit 10.4 to our Annual Report on Form 10-K for the year ended December 31, 2002).
10.8	—	Omnibus Agreement, dated December 17, 2002, among Crosstex Energy, L.P. and certain other parties (incorporated by reference to Exhibit 10.5 to our Annual Report on Form 10-K for the year ended December 31, 2002).
10.9	—	Form of Employment Agreement (incorporated by reference to Exhibit 10.6 to our Annual Report on Form 10-K for the year ended December 31, 2002).
10.10	—	Gas Sales Agreement, dated March 1, 2001 among Tejas Gas Marketing, LLC, Corpus Christi Gas Marketing, L.P. and Corpus Christi Gas Processing, L.P., as amended by the Amendment to Gas Sales Agreement, dated October 1, 2001, among Tejas Gas Marketing, LLC and Crosstex CCNG Marketing, L.P. (incorporated by reference to Exhibit 10.6 to our Registration Statement on Form S-1, file No. 333-97779).
10.11	—	Gas Sales Agreement, dated December 17, 1998, among Reliant Energy Entex and GC Marketing Company, as amended by the Amendment to Gas Sales Agreement, dated June 18, 2002, among Crosstex Gulf Coast Marketing, Ltd. and Reliant Energy Entex (incorporated by reference to Exhibit 10.7 to our Registration Statement on Form S-1, file No. 333-97779).
10.12	—	Seminole Gas Processing Plant Gaines County, Texas Joint Operating Agreement dated January 1, 1993 (incorporated by reference to Exhibit 10.10 to our Registration Statement on Form S-1, file No. 333-106927).

10.13	—	Purchase and Sale Agreement between Duke Energy Field Services, L.P. and Crosstex Energy Services, L.P., dated April 29, 2003. (incorporated by reference to Exhibit 10.11 to our Registration Statement on Form S-1, file No. 333-97779).
21.1*	—	List of Subsidiaries
23.1**	—	Consent of Independent Registered Public Accounting Firm.
31.1**	—	Certification of the principal executive officer.
31.2**	—	Certification of the principal financial officer.
32.1**	—	Certification of the principal executive officer and the principal financial officer of the Company pursuant to 18 U.S.C. Section 1350.

* Previously filed.

** Filed herewith.

+ Compensatory benefit plan or arrangement in which directors and executive officers are eligible to participate.

(b) Reports on Form 8-K.

On November 12, 2003, Crosstex Energy, L.P. filed or furnished a Current Report on Form 8-K (dated as of November 13, 2003) which included its press release as Exhibit 99.1 announcing its financial results for the quarter ended September 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 9th day of August 2004.

CROSSTEX ENERGY, L.P.

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

By: Crosstex Energy GP, LLC,
its general partner

By: /s/ BARRY E. DAVIS

Barry E. Davis,
President and Chief Executive Officer

INDEX TO FINANCIAL STATEMENTS

Crosstex Energy, L.P. Financial Statements:

Report of Independent Registered Public Accounting Firm

The Partners
Crosstex Energy, L.P.:

We have audited the accompanying consolidated balance sheets of Crosstex Energy, L.P. (a Delaware limited partnership) and subsidiaries as of December 31, 2003 and 2002 and the related consolidated statements of operations, changes in partners' equity, comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2003. In connection with the audits of the consolidated financial statements, we also have audited the accompanying financial statement schedule. These financial statements and financial statement schedule are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Crosstex Energy, L.P. and subsidiaries as of December 31, 2003 and 2002, and the consolidated results of their operations, comprehensive income, and their cash flows for each of the years in the three-year period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the related financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects the information set forth therein.

As explained in note 3 to the consolidated financial statements, effective January 1, 2001, the Partnership changed its method of accounting for derivatives. Also, as explained in note 3 to the consolidated financial statements, effective January 1, 2002, the Partnership changed its method of amortizing goodwill.

As discussed in note 2 to the accompanying consolidated financial statements, the accompanying balance sheets as of December 31, 2003 and 2002, the consolidated statements of changes in partners' equity for the years ended December 31, 2003 and 2002 and the consolidated statements of operations, cash flows and comprehensive income for the year ended December 31, 2002 have been restated.

/s/ KPMG LLP

Dallas, Texas
February 26, 2004 except as to note 2, which is as of July 28, 2004

CROSSTEX ENERGY, L.P.

Consolidated Balance Sheets

December 31, 2003 and 2002

(In thousands)

	2003 (Restated)	2002 (Restated)
Assets		
Current assets:		
Cash and cash equivalents	$ 166	$ 1,308
Accounts receivable:		
Trade	10,238	27,049
Accrued revenues	124,517	78,500
Imbalances	447	79
Related party	1,618	—
Note receivable	535	—
Other	2,588	637
Fair value of derivative assets	4,080	2,947
Prepaid expenses and other	1,979	1,225
Total current assets	146,168	111,745
Property and equipment:		
Transmission assets	99,650	50,391
Gathering systems	27,990	22,624
Gas plants	87,140	39,475
Other property and equipment	3,743	2,754
Construction in process	9,863	6,935
Total property and equipment	228,386	122,179
Accumulated depreciation	(24,477)	(12,231)
Total property and equipment, net	203,909	109,948
Fair value of derivative assets	—	155
Intangible assets, net	5,366	5,340
Goodwill, net	4,873	4,873
Investment in limited partnerships	2,560	346
Other assets, net	3,174	778
Total assets	$ 366,050	$ 233,185
Liabilities and Partners' Equity		
Current liabilities:		
Drafts payable	$ 10,446	$ 27,546
Accounts payable	6,325	10,740
Accrued gas purchases	119,900	74,912
Accounts payable—related party	448	—
Accrued imbalances payable	212	149
Fair value of derivative liabilities	2,487	4,006
Current portion of long-term debt	50	50
Other current liabilities	10,872	4,672
Total current liabilities	150,740	122,075
Long-term debt	60,700	22,500
Fair value of derivative liabilities	—	452
Partners' equity:		
Common unit-holders (4,358,000 and 2,633,000 units issued and outstanding at December 31, 2003 and 2002, respectively)	116,780	57,561
Subordinated unit-holders (4,667,000 units issued and outstanding at December 31, 2003 and 2002)	33,593	30,790
General partner interest (2% interest with 184,000 and 149,000 equivalent units outstanding at December 31, 2003 and 2002, respectively)	2,854	983
Accumulated other comprehensive income (loss)	1,383	(1,176)
Total partners' equity	154,610	88,158
Total liabilities and partners' equity	$ 366,050	$ 233,185

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Operations

(In thousands, except per unit amounts)

	Years ended December 31, 2003	2002 (Restated)	2001
Revenues:			
Midstream	$ 993,140	$ 437,432	$ 362,673
Treating	20,523	14,817	24,353
Total revenues	1,013,663	452,249	387,026
Operating costs and expenses:			
Midstream purchased gas	946,412	414,244	344,755
Treating purchased gas	7,568	5,767	18,078
Operating expenses	17,692	11,409	7,761
General and administrative	6,844	7,513	5,583
Stock based compensation	5,345	41	—
Impairments	—	4,175	2,873
(Profit) loss on energy trading activities	(1,905)	(1,657)	3,714
Depreciation and amortization	13,268	7,745	6,101
Total operating costs and expenses	995,224	449,237	388,865
Operating income (loss)	18,439	3,012	(1,839)
Other income (expense):			
Interest expense, net	(3,392)	(2,717)	(2,253)
Other income	179	49	174
Total other income (expense)	(3,213)	(2,668)	(2,079)
Net income (loss)	$ 15,226	$ 344	$ (3,918)
Allocation of 2002 net income:			
Net income for the period from January 1, 2002 to December 16, 2002	—	$ 24	—
Net income for the period from December 17, 2002 to December 31, 2002	—	320	—
Net income	—	$ 344	—
General partner interest in net income for the period from December 17, 2002 to December 31, 2002 and for the year ended December 31, 2003	$ 1,240	$ 6	—
Limited partners' interest in net income for the period from December 17, 2002 to December 31, 2002 and for the year ended December 31, 2003	$ 13,986	$ 314	—
Net income per limited partners' unit:			
Basic	$ 1.78	$ 0.04	—
Diluted	$ 1.75	$ 0.04	—
Weighted average limited partners' units outstanding			
Basic	7,876	7,300	—
Diluted	7,980	7,310	—

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Changes in Partners' Equity

Years ended December 31, 2003 (Restated), 2002 (Restated) and 2001

(In thousands)

	Crosstex Energy Services, Ltd. Partners' equity	Crosstex Energy L.P. Common units	Subordinated units	General partner interest	Accumulated other comprehensive income	Total
Balance, December 31, 2000	$ 40,354	$ —	$ —	$ —	$ —	$ 40,354
Capital contributions	5,019	—	—	—	—	5,019
Distributions	(442)	—	—	—	—	(442)
Net loss	(3,918)	—	—	—	—	(3,918)
Cumulative adjustment from adoption of accounting standard	—	—	—	—	(1,006)	(1,006)
Hedging gains or losses reclassified to earnings	—	—	—	—	1,006	1,006
Adjustment in fair value of derivatives	—	—	—	—	142	142
Balance, December 31, 2001	41,013	—	—	—	142	41,155
Assets not contributed to Crosstex Energy, L.P.	(3,754)	—	—	—	—	(3,754)
Capital contributions	14,000	—	—	—	—	14,000
Stock based compensation	41	—	—	—	—	41
Net income from January 1, 2002 through December 16, 2002 (restated)	24	—	—	—	—	24
Distributions	(2,500)	—	—	—	—	(2,500)
Transfer of equity in accordance with initial public offering	(48,824)	17,258	30,589	976	—	—
Net proceeds from initial public offering	—	40,190	—	—	—	40,190
Net income from December 17, 2002 through December 31, 2002	—	113	201	6	—	320
Hedging gains or losses reclassified to earnings	—	—	—	—	(178)	(178)
Adjustment in fair value of derivatives	—	—	—	—	(1,140)	(1,140)
Balance, December 31, 2002 (restated)	—	57,561	30,790	983	(1,176)	88,158
Net proceeds from issuance of common units	—	57,336	—	—	—	57,336
Capital contributions	—	—	—	1,266	—	1,266
Stock based compensation	—	2,121	3,117	107	—	5,345
Distributions	—	(6,016)	(8,522)	(742)	—	(15,280)
Net income	—	5,778	8,208	1,240	—	15,226
Hedging gains or losses reclassified to earnings	—	—	—	—	4,267	4,267
Adjustment in fair value of derivatives	—	—	—	—	(1,708)	(1,708)
Balance, December 31, 2003 (restated)	$ —	$ 116,780	$ 33,593	$ 2,854	$ 1,383	$ 154,610

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Comprehensive Income

December 31, 2003, 2002 and 2001

(In thousands)

	2003	2002 (Restated)	2001
Net income (loss)	$ 15,226	$ 344	$ (3,918)
Cumulative adjustment from adoption of accounting standard	—	—	(1,006)
Hedging gains or losses reclassified to earnings	4,020	(178)	1,006
Adjustment in fair value of derivatives	(1,461)	(1,140)	142
Comprehensive income (loss)	$ 17,785	$ (974)	$ (3,776)

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Cash Flows

(In thousands)

	Years ended December 31, 2003	2002 (Restated)	2001
Cash flows from operating activities:			
Net income (loss)	$ 15,226	$ 344	(3,918)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Depreciation and amortization	13,268	7,745	6,101
Impairments	—	4,175	2,873
Income (loss) on investment in affiliated partnerships	(208)	41	(35)
Non-cash stock based compensation	5,345	41	—
Changes in assets and liabilities, net of acquisition effects:			
Accounts receivable and accrued revenue	(33,143)	(47,291)	47,565
Prepaid expenses	(754)	178	(1,566)
Accounts payable, accrued gas purchases, and other accrued liabilities	41,084	31,204	(65,033)
Fair value of derivatives	(208)	(4,669)	4,573
Other	5,850	2,560	(804)
Net cash provided by (used in) operating activities	46,460	(5,672)	(10,244)
Cash flows from investing activities:			
Additions to property and equipment	(39,003)	(14,545)	(22,685)
Asset purchases	(68,124)	(18,785)	(30,003)
Additions to other non-current assets	(1,027)	—	—
Distributions from (investments in) affiliated partnerships	(2,135)	90	153
Net cash used in investing activities	(110,289)	(33,240)	(52,535)
Cash flows from financing activities:			
Proceeds from borrowings	320,100	384,050	267,131
Payments on borrowings	(281,900)	(421,500)	(229,150)
Drafts payable	(17,100)	25,628	1,918
Debt refinancing costs	(1,735)	—	—
Distribution to partners	(15,280)	(2,500)	(442)
Net proceeds from public equity offerings	57,336	40,190	—
Contribution from partners	1,266	14,000	5,019
Net cash provided by financing activities	62,687	39,868	44,476
Net increase (decrease) in cash and cash equivalents	(1,142)	956	(18,303)
Cash and cash equivalents, beginning of period	1,308	352	18,655
Cash and cash equivalents, end of period	$ 166	$ 1,308	$ 352
Cash paid for interest	$ 3,388	$ 2,558	$ 2,720
Non-cash transactions—stock based compensation	$ 5,345	$ 41	—
Assets not contributed to Crosstex Energy, L.P.	—	$ 3,754	—

See accompanying notes to consolidated financial statements.

(1) Organization and Summary of Significant Agreements

(a) Description of Business

Crosstex Energy, L.P. (the Partnership), a Delaware limited partnership formed on July 12, 2002, is engaged in the gathering, transmission, treating, processing and marketing of natural gas. The Partnership connects the wells of natural gas producers in the geographic areas of its gathering systems in order to purchase the gas production, treats natural gas to remove impurities to ensure that it meets pipeline quality specifications, processes natural gas for the removal of natural gas liquids or NGLs, transports natural gas and ultimately provides an aggregated supply of natural gas to a variety of markets. In addition, the Partnership purchases natural gas from producers not connected to its gathering systems for resale and sells natural gas on behalf of producers for a fee.

(b) 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. (CEI, formerly Crosstex Energy Holdings). CEI 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 CEI including (i) the Jonesville and Clarkson gas plants, (ii) the Enron receivable and related derivative positions, and (iii) the right to receive a cash distribution of $2.5 million.

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

See Note 6 for a discussion of the Partnership's September 2003 sale of additional common units.

As of December 31, 2003, Yorktown Energy Partners IV, L.P. and Yorktown Energy Partners V, L.P. (collectively, Yorktown) owned 77% of CEI and CES management and directors owned 23% of CEI. In January 2004, CEI completed an initial public offering of its common stock. After giving effect to this public offering, Yorktown owns 60.2% of CEI's outstanding common shares, CES management and directors own 17.8% of CEI's outstanding common shares and the remaining 22.0% is held publicly.

(c) Basis of Presentation

The accompanying consolidated financial statements include the assets, liabilities, and results of operations of the Partnership (or CES as its predecessor) and its wholly owned subsidiaries. The consolidated operations are hereafter referred to herein collectively as the "Partnership." All material intercompany balances and transactions have been eliminated. Certain reclassifications have been made to the consolidated financial statements for the prior years to conform to the current presentation.

(2) Restatement of Previously Issued Financial Statements

In July 2004, we determined that certain clerical errors had occurred in 2002 accounting that resulted in certain reconciling items not being properly cleared from accounts payable, accounts receivable and accrued gas purchases resulting in a decrease in income of $1.7 million. As a result of correcting these errors, we have restated our consolidated statement of operations for the year ended December 31, 2002, our consolidated balance sheets as of December 31, 2003 and 2002, our consolidated statement of cash flows for the year ended December 31, 2002, our consolidated statements of changes in partners' equity for the years ended December 31, 2003 and 2002, and our consolidated statement of comprehensive income for the year ended December 31, 2002.

The effects of the revisions on our consolidated statement of operations for the year ended December 31, 2002 are summarized in the following table (in thousands):

	Previously Reported	As Restated
Revenues:		
Midstream	$ 437,676	$ 437,432
Total Revenues	452,493	452,249
Operating Costs and Expenses:		
Midstream purchased gas	413,982	414,244
Energy trading activities	(2,703)	(1,657)
Total operating costs and expenses	447,929	449,237
Operating Income (loss)	4,564	3,012
Other income (expense):		
Other income	155	49
Total other income (expense)	(2,562)	(2,668)
Net income (loss)	$ 2,002	$ 344
Allocation of 2002 net income:		
Net income for the period from January 1, 2002 to December 16, 2002	$ 1,682	$ 24

The restatement had no impact on net income per limited partners' unit as previously reported, due to the fact that the related errors occurred prior to December 16, 2002.

The effects of the revisions on our consolidated balance sheets as of December 31, 2003 and 2002 are summarized in the following table (in thousands):

	Previously Reported		As Restated	
	2003	2002	2003	2002
Accounts receivable—Trade	9,491	26,302	10,238	27,049
Total current assets	145,421	110,998	146,168	111,745
Total property and equipment, net	203,909	109,948	203,909	109,948
Total assets	365,303	232,438	366,050	233,185
Accounts payable	4,064	8,479	6,325	10,740
Accrued gas purchases	119,756	74,768	119,900	74,912
Total current liabilities	148,335	119,670	150,740	122,075
Long-term debt	60,700	22,500	60,700	22,500
Partners' equity				
Common unit-holders (4.358,000 and 2,633,000 units issued and outstanding At December 31, 2003 and 2002, respectively	117,366	58,147	116,780	57,561
Subordinated unit-holders (4,667,000 and issued and outstanding At December 31, 2003 and 2002)	34,632	31,829	33,593	30,790
General partner interest (2% interest with 184,000 and 149,000 equivalent untis outstanding At December 31, 2003 and 2002, respectively	2,887	1,016	2,854	983
Accumulated other comprehensive income	1,383	(1,176)	1,383	(1,176)
Total partner's equity	156,268	89,816	154,610	88,158
Total liabilities and partners' equity	365,303	232,438	366,050	233,185

The effects of the revisions on our consolidated statement of changes in partners' equity are a decrease to net income from January 1, 2002 through December 16, 2002 by $1.7 million and a corresponding decrease in transfer of equity in accordance with initial public offering of $0.6 million for common unit-holders, $1.0 million for subordinated unit-holders, and $33,000 for general partner interest.

The effects of the revisions on our consolidated statement of cash flows for the year ended December 31, 2002 are summarized in the following table (in thousands):

	Previously Reported	As Restated
Net income (loss)	$ 2,002	$ 344
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:		
Changes in assets and liabilities, net of acquisition effects:		
Accounts receivable and accrued revenue	(46,544)	(47,291)
Accounts payable, accrued gas purchases, and other accrued liabilities	28,799	31,204
Net cash provided by (used in) operating activities	(5,672)	(5,672)
Net cash provided by (used in) investing activities	(33,240)	(33,240)
Net cash provided by (used in) financing activities	39,868	39,868

There was no net impact on cash flows due to the restatement.

The effects of the revisions on our consolidated statement of comprehensive income for the year ended December 31, 2002 are summarized in the following table (in thousands):

	Previously Reported	As Restated
Net income (loss)	$ 2,002	$ 344
Hedging gains or losses reclassified to earnings	(178)	(178)
Adjustment in fair value of derivatives	(1,140)	(1,140)
Comprehensive income	$ 684	$ (974)

The segment information in note 14 and the quarterly financial data in note 15 have been restated to reflect the impact of the correction of the clerical errors.

(3) Significant Accounting Policies

(a) Management's Use of Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America requires management of the Partnership to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from these estimates.

(b) Cash and Cash Equivalents

The Partnership considers all highly liquid investments with an original maturity of three months or less to be cash equivalents.

(c) Property, Plant, and Equipment

Property, plant, and equipment consist of intrastate gas transmission systems, gas gathering systems, industrial supply pipelines, natural gas processing plants, an undivided 12.4% interest in a carbon dioxide processing plant, and gas treating plants.

Other property and equipment is primarily comprised of furniture, fixtures, and office equipment. Such items are depreciated over their estimated useful life of five years. Property, plant, and equipment are recorded at cost. Repairs and maintenance are charged against income when incurred. Renewals and betterments, which extend the useful life of the properties, are capitalized. Depreciation is provided using the straight-line method based on the estimated useful life of each asset, as follows:

	Useful lives
Transmission assets	15 years
Gathering systems	7-15 years
Gas treating, gas processing and carbon dioxide plants	10-15 years
Other property and equipment	5 years

Statement of Financial Accounting Standards (SFAS) No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, requires long-lived assets to be reviewed whenever events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. In order to determine whether an impairment has occurred, the Partnership compares the net book value of the asset to the undiscounted expected future net cash flows. If impairment has occurred, the amount of such impairment is determined based on the expected future net cash flows discounted using a rate commensurate with the risk associated with the asset. Impairments of approximately $4,175,000 and $2,873,000 associated with certain assets and the related intangible assets were recorded in the years ended December 31, 2002 and 2001, respectively. The impairments recorded in 2002 and 2001 relate primarily to customer relationships recorded as intangible assets as part of CES's formation. Due to changes impacting the expected future cash flows of the related assets, the Partnership determined the intangible assets were impaired under SFAS No. 121 or SFAS No. 144.

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

(d) Amortization of Intangibles

Until January 1, 2002, goodwill was amortized on a straight-line basis over 15 years. Such amortization was $296,000 for the year ended December 31, 2001. The Partnership discontinued the amortization of goodwill effective January 1, 2002 with the adoption of SFAS No. 142. As of December 31, 2003, accumulated amortization of goodwill was $508,000.

The following table shows the Partnership's net loss excluding goodwill amortization for the year ended December 31, 2001 (in thousands).

Reported net income (loss)	$	(3,918)
Goodwill amortization		296
Adjusted net income (loss)	$	(3,622)

The Partnership has approximately $4.9 million of goodwill at December 31, 2003 which resulted from the formation of the Partnership in May 2000. The goodwill has been allocated to the Midstream segment and is assessed at least annually for impairment. During the fourth quarter of 2003, the Partnership completed the annual impairment testing of goodwill and no impairment was required.

Intangible assets are amortized on a straight-line basis over the expected period of benefits of the customer relationships, which average six years. Such amortization was approximately $896,000, $454,000 and $772,000 for the years ended December 31, 2003, 2002 and 2001, respectively. See impairment of intangibles discussed in note 2(c). As of December 31, 2003, accumulated amortization of intangible assets was $2,089,000.

(e) Other Assets

Unamortized debt issuance costs totaling $2.1 million as of December 31, 2003 are included in other noncurrent assets. Debt issuance costs are amortized into interest expense over the term of the related debt. Other noncurrent assets as of December 31, 2003 also include the noncurrent portion of the note receivable from Adkins discussed in Note 4.

(f) Gas Imbalance Accounting

Quantities of natural gas over-delivered or under-delivered related to imbalance agreements are recorded monthly as receivables or payables using weighted average prices at the time the imbalance was created. These imbalances are typically settled with deliveries of natural gas. The Partnership had an imbalance payable of $212,000 and $149,000, and an imbalance receivable of $447,000 and $79,000 at December 31, 2003 and 2002, respectively. Imbalance receivables are carried at the lower of cost or market value.

(g) Revenue Recognition

The Partnership recognizes revenue for sales or services at the time the natural gas, carbon dioxide, or NGLs are delivered or at the time the service is performed. See discussion of accounting for energy trading activities in note 2(i).

(h) Commodity Risk Management

The Partnership engages in price risk management activities in order to minimize the risk from market fluctuation in the price of natural gas and NGLs. To qualify as a hedge, the price movements in the commodity derivatives must be highly correlated with the underlying hedged commodity. Gains and losses related to commodity derivatives which qualify as hedges are recognized in income when the underlying hedged physical transaction closes and are included in the consolidated statements of operations as a cost of gas purchased.

Effective January 1, 2001, the Partnership adopted Statement of Financial Accounting Standards No. 133 (SFAS 133),*Accounting for Derivative Instruments and Hedging Activities*. This standard requires recognition of all derivative and hedging instruments in the statements of financial position as either assets or liabilities and measures them at fair value. If a derivative does not qualify for hedge accounting, it must be adjusted to fair value through earnings. However, if a derivative does qualify for hedge accounting, depending on the nature of the hedge, changes in fair value can be offset against the change in 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.

To qualify for cash flow hedge accounting, the cash flows from the hedging instrument must be highly effective in offsetting changes in cash flows due to changes in the underlying item being hedged. In addition, all hedging relationships must be designated, documented, and reassessed periodically. The impact of adopting SFAS No. 133 on January 1, 2001, was to record the fair value of derivatives as a liability and accumulated other comprehensive income in the amount of $1,006,000.

Currently, all derivative financial instruments that qualify for hedge accounting are designated as cash flow hedges. These instruments hedge the exposure of variability in expected future cash flows that is attributable to a particular risk. The effective portion of the gain or loss on these derivative instruments is recorded in other comprehensive income in partners' equity and reclassified into earnings in the same period in which the hedged transaction affects earnings. The asset or liability related to the derivative instruments is recorded on the balance sheet in fair value of derivative assets or liabilities. Any ineffective portion of the gain or loss is recognized in earnings immediately.

(i) Producer Services

The Partnership conducts "off-system" gas marketing operations as a service to producers on systems that the Partnership does not own. The Partnership refers to these activities as part of Producer Services. In some cases, the Partnership earns an agency fee from the producer for arranging the marketing of the producer's natural gas. In other cases, the Partnership purchases the natural gas from the producer and enters into a sales contract with another party to sell the natural gas.

The Partnership manages its price risk related to future physical purchase or sale commitments for its Producer Services activities by entering into either corresponding physical delivery contracts or financial instruments with an objective to balance the Partnership's future commitments and significantly reduce its risk to the movement in natural gas prices. However, the Partnership is subject to counter-party risk for both the physical and financial contracts. Prior to October 26, 2002, the Partnership accounted for its 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. The Partnership's energy trading contracts qualify as derivatives, and accordingly, the Partnership continues to use mark-to-market accounting for both physical and financial contracts of its Producer Services business. Accordingly, any gain or loss associated with changes in the fair value of derivatives and physical delivery contracts relating to the Partnership's Producer Services natural gas marketing activities are recognized in earnings as profit or loss on energy trading contracts immediately.

For each reporting period, the Partnership records 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 net as profit or loss on energy trading contracts in the statements of operations.

Margins earned on settled contracts from its producer services activities included in profit (loss) on energy trading contracts in the consolidated statement of operations was $2,231,000, $1,791,000 and $1,946,000 for the years ended December 31, 2003, 2002 and 2001, respectively.

Energy trading contract volumes that were physically settled were as follows (in MMBtus):

	Years ended December 31,		
	2003	2002	2001
Volumes purchased and sold	94,572,000	84,069,000	103,331,000

(j) Comprehensive Income (Loss)

Comprehensive income includes net income and other comprehensive income, which includes, but is not limited to, unrealized gains and losses on marketable securities, foreign currency translation adjustments, minimum pension liability adjustments, and effective January 1, 2001, unrealized gains and losses on derivative financial instruments.

With the adoption of SFAS No. 133 on January 1, 2001, the Partnership began recording deferred hedge gains and losses on its derivative financial instruments that qualify as cash flow hedges as other comprehensive income.

(k) Income Taxes

No provision is made in the accounts of the Partnership for federal or state income taxes because such taxes are liabilities of the individual partners, and the amounts thereof depend upon their respective tax situations. The tax returns and amounts of allocable Partnership revenues and expenses are subject to examination by federal and state taxing authorities. If such examinations result in changes to allocable Partnership revenues and expenses, the tax liability of the Partners could be changed accordingly.

(l) Concentrations of Credit Risk

Financial instruments, which potentially subject the Partnership to concentrations of credit risk, consist primarily of trade accounts receivable and derivative financial instruments. Management believes the risk is limited, as the Partnership's customers represent a broad and diverse group of energy marketers and end users. In addition, the Partnership continually monitors and reviews credit exposure to its marketing counter-parties and letters of credit or other appropriate security are obtained as considered necessary to limit the risk of loss. As of December 31, 2003 and 2002, the Partnership had no reserves for doubtful accounts. See note 10 for further discussion.

During the years ended December 31, 2003, 2002 and 2001, the Partnership had 1, 1, and 3 customers, respectively, which individually accounted for more than 10% of consolidated revenues. The relevant percentages for these customers were: (i) for the year ended December 31, 2003—20.5%; (ii) for the year ended December 31, 2002—27.5%; and (iii) for the year ended December 31, 2001—23.9%, 13.4%, and 11.5%. While these customers represent a significant percentage of revenues, the loss of any of these would not have a material adverse impact on the Partnership's results of operations.

(m) Environmental Costs

Environmental expenditures are expensed or capitalized as appropriate, depending on the nature of the expenditures and their future economic benefit. Expenditures that related to an existing condition caused by past operations that do not contribute to current or future revenue generation are expensed. Liabilities for these expenditures are recorded on an undiscounted basis (or discounted when the obligation can be settled at fixed and determinable amounts) when environmental assessments or clean-ups are probable and the costs can be reasonably estimated. For years ended December 31, 2003, 2002 and 2001, such expenditures were not significant.

(n) Option Plans

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 the plan. In accordance with APB No. 25 for fixed stock and unit options, compensation is recorded to the extent the fair value of the stock or unit exceeds the exercise price of the option at the measurement date. Compensation costs for fixed awards with pro rata vesting are recognized on a straight-line basis over the vesting period. In addition, compensation expense is recorded for variable options based on the difference between fair value of the stock or unit and exercise price of the options at period end. Compensation expense of $5,345,000, $41,000, and $0 was recognized in 2003, 2002, and 2001, respectively. The portion of compensation expense for 2003 related to operating activities was $2,122,000 and the remaining expense of $3,223,000 related to general and administrative activities.

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

	Year ended December 31,		
	2003	2002 (Restated)	2001
Net income, as reported and restated	$ 15,226	$ 344	$ (3,918)
Add: Stock-based employee compensation expense included in reported net income	5,345	41	—
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards	(5,594)	(328)	(226)
Pro forma net income	$ 14,977	$ 57	$ (4,144)

	Year ended December 31, 2003
Net income per limited partner unit, as reported:	
Basic	$ 1.78
Diluted	$ 1.75
Pro forma net income per limited partner unit:	
Basic	$ 1.74
Diluted	$ 1.72

Actual and pro forma earnings per unit for the period December 17, 2002 through December 31, 2002 would have been $0.04 per unit.

The fair value of each option is estimated on the date of grant using the Black Scholes option-pricing model with the following weighted average assumptions used for grants in 2003, 2002, and 2001:

	Crosstex Energy, Inc.		Crosstex Energy, L.P.	
	2002	2001	2003	2002
Weighted average dividend yield	0%	0%	9.8%	10%
Weighted average expected volatility	0%	0%	24%	24%
Weighted average risk free interest rate	4.1%	5.8%	2.65%	2.2%
Weighted average expected life	3 years	3 years	4.3 years	3 years
Contractual life	3	3.6	10	10
Weighted average of fair value of unit options granted	—	—	$ 2.56	$ 1.15
Fair value of $5 stock options granted*	$ 1.59	$ 1.64	—	—
Fair value of $6 stock options granted*	0.70	0.76	—	—
Fair value of $7 stock options granted*	0.46	—	—	—

* Fair values and option prices have been adjusted for the two-for-one stock split made in connection with CEI's January 2004 initial public offering.

No Crosstex Energy, Inc. options were granted in 2003. Stock based compensation associated with the CEI option plan is recorded by the Partnership since CEI has no operating activities other than its interest in the Partnership.

(o) 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 was adopted by the Partnership 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 the Partnership's results of operations or financial position.

SFAS No. 148, *Accounting for Stock-Based Compensation-Transition and Disclosure, an amendment of FASB Statement No. 123* SFAS No. 148 amends SFAS No. 123 and provides alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. SFAS No. 148 also requires prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based compensation and the effect of the method used on reported results. SFAS No. 148 permits two additional transition methods for entities that adopt the fair value based method, these methods allow Companies to avoid the ramp-up effect arising from prospective application of the fair value based method. This Statement is effective for financial statements for fiscal years ended after December 15, 2002. The Partnership has complied with the disclosure provisions of the Statement in its financial statements.

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 ended 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.* In December 2003, the FASB issued FIN No. 46R which clarified certain issues identified in FIN 46. FIN No. 46R 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 March 15, 2004. 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. 46R will require the consolidation of any of these investments, however, the Partnership currently believes that one of its joint venture interests, as described in Note 4 to the financial statements, will be consolidated in the financial statements when FIN No. 46R is adopted in March 2004.

The FASB issued Statement of Financial Accounting Standards No. 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity," ("SFAS No. 150") in May 2003. SFAS No. 150 establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. The Partnership has no financial instruments which are subject to SFAS No. 150.

(4) Significant Asset Purchases and Acquisitions

On April 3, 2001, CES entered into a purchase and sale agreement with Tejas Energy NS, LLC to acquire all of the assets of Tejas Texas Pipeline GP, LLC, a Delaware limited liability company, and Tejas C Pipeline LP, LLC, a Delaware limited liability company, for a total purchase price of $30,003,000, after closing adjustments. CES recorded the net assets acquired based on relative fair values, and CES's results of operations include the results of operations of the acquired assets as of May 1, 2001.

The purchase price consisted of the following (in thousands):

Gas plant	$	11,837
Gathering systems		10,192
Transmission assets		7,158
Other property, plant, and equipment		816
	$	30,003

On October 11, 2001, CES entered into a purchase and sale agreement with various individuals to acquire the common stock of Millennium Gas Services, Inc. (Millennium) for a total of $2,124,000 after closing adjustments, which was allocated entirely to treating plants. CES's results of operations include the results of Millennium as of October 1, 2001.

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.

On June 30, 2003, the Partnership completed the acquisition of certain assets from Duke Energy Field Services, L.P. (DEFS) 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 Alabama pipeline system. The Partnership has 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. Unaudited pro forma results of operations as if the acquisition from DEFS had been acquired on January 1, 2002 are as follows (in thousands, except per unit amounts):

	Years Ended December 31,	
	2003	2002 (Restated)
Revenue	$ 1,119,985	$ 589,504
Net income	16,216	2,346
Net income per limited partner unit	$ 1.90	—

(5) Investment in Limited Partnerships and Note Receivable

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, 50% interest in the J.O.B. J.V. and a 50% interest in Crosstex Denton County Gathering, J.V. (CDC). The Partnership accounts for its investments under the equity method, as it exercises significant influence in operating decisions as a general partner in CPC and as a 50% owner in the joint ventures. Under this method, the Partnership carries its investments at cost and 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.

CDC was formed to build, own and operate a natural gas gathering system in Denton County, Texas. The Partnership manages the business affairs of CDC. The other 50% joint venture partner (the CDC Partner) is an unrelated third party and owns and operates natural gas wells connected to the CDC gathering systems.

In connection with the formation of CDC, the Partnership agreed to loan the CDC Partner up to $1.5 million for their initial capital contribution. The loan bears interest at an annual rate of prime plus 2%. CDC makes payments directly to the Partnership attributable to CDC Partner's 50% share of distributable cash flow to repay the loan. Any balance remaining on the note is due in August 2007. The current portion of loan receivable of $535,000 from the CDC Partner is included in current notes receivable. The remaining balance of $1,027,000 is included in other non-current assets.

The Partnership's investment in CDC is $2.3 million as of December 31, 2003. The Partnership also has $635,000 in receivables from affiliates for cash advances to CDC for current disbursements that are generally repaid on a month-to-month basis in the normal course of business. The Partnership's investment at risk of CDC at December 31, 2003, is approximately $4.5 million, including cash advances and the note receivable from the CDC Partner.

Summarized financial information for 100% of CDC for the year ended December 31, 2003 is as follows (in thousands):

Revenues	$	203
Costs and expenses		(248)
Net Loss	$	(45)
Current assets	$	322
Noncurrent assets		4,513
Current liabilities		809
Noncurrent liabilities		—
Partners' equity		4,026

(6) Long-Term Debt

At December 31, 2002, the Partnership had amended the secured credit facility with Union Bank of California, N.A. ("UBOC") to provide a $67.5 million credit facility consisting of a senior secured revolving acquisition facility in the aggregate principal amount of $47.5 million and a senior secured revolving working capital facility in the aggregate principal amount of $20 million.

In June 2003, CES entered into a $100 million senior secured credit facility with UBOC (as a lender and administrative agent) and four other banks, 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 will be used to finance the acquisition and development of gas gathering, treating, and processing facilities, as well as general partnership purposes. At December 31, 2003, $20.0 million was outstanding under the acquisition facility, leaving approximately $50.0 million available for future borrowings. 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 re-borrowed.

The working capital and letter of credit facility will be used for ongoing working capital needs, letters of credit, distributions and general partnership purposes, including future acquisitions and expansions. At December 31, 2003, $30.3 million of letters of credit were issued under the working capital facility, leaving approximately $19.7 million available for future issuances of letters of credit, or up to $19.7 million of 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 $25.0 million sub-limit 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 facility may be re-borrowed. We are required to reduce all working capital borrowings to zero for a period of at least 15 consecutive days once a year.

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

Indebtedness under the acquisition facility and the working capital facility bear interest at our option at the administrative agent's reference rate plus 0.25% to 1.5% 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. We incur quarterly commitment fees based on the unused amount of the credit facilities.

The credit agreement prohibits us from declaring distributions to unit-holders 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 agreement; and
- engage in transactions with affiliates.

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

- a maximum ratio of funded debt to consolidated EBITDA (each as defined in the 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 bank credit facility), measured quarterly on a rolling four quarter basis equal to 3.50 to 1;

- a minimum current ratio (as defined in the credit agreement), measured quarterly of 1 to l; and
- a minimum tangible net worth (as defined in the credit agreement) of $60 million, plus one-half of certain equity contributions.

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;
- 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 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, 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 purchasers 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.

Other Note Payable. 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 December 31, 2003 and 2002, long-term debt consisted of the following (in thousands):

	2003	2002
Acquisition credit facility, interest based at prime plus an applicable margin, interest rate at December 31, 2002 was 4.88%	$ —	$ 1,750
Acquisition credit facility, interest based on LIBOR plus an applicable margin, interest rates at December 31, 2003 and 2002 were 2.92% and 3.95%, respectively	20,000	20,000
Senior secured notes, weighted average interest rate of 6.93%	40,000	—
Note payable to Florida Gas Transmission Company	750	800
	60,750	22,550
Less current portion	(50)	(50)
Debt classified as long-term	$ 60,700	$ 22,500

Maturities for the long-term debt as of December 31, 2003 are as follows (in thousands):

2004	$ 50
2005	50
2006	28,874
2007	10,012
2008	9,412
Thereafter	12,352

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 which expires on November 1, 2004. The Partnership has accounted for this swap as a cash flow hedge of the variable interest payments related to the $20 million of the acquisition credit facility outstanding. Accordingly, unrealized gains or losses relating to the swap which are recorded in other comprehensive income will be reclassified from other comprehensive income to interest expense over the period hedged. The fair value of the interest rate swap at December 31, 2003 was a $209,000 liability and is included in fair value of derivative liabilities.

(7) Partners' Capital

(a) Initial Public Offering

On December 17, 2002, the Partnership completed its initial public offering of 2,300,000 common units representing limited partner interests at a price of $20.00 per common unit. Total proceeds from the sale of the 2,300,000 units were $46.0 million, before offering costs and underwriting commissions. Concurrent with the closing of the initial public offering, the Partnership entered into a $67.5 million credit facility with a syndicate of banks led by Union Bank of California, that provides for a $47.5 million acquisition credit facility and a $20 million working capital facility (see note 5). On December 17, 2002, the Partnership had borrowings of $20 million under the acquisition credit facility.

A summary of the proceeds received from the offering and the use of those proceeds is as follows (in thousands):

Proceeds received:		
Sale of common units	$	46,000
Use of proceeds:		
Underwriters' fees	$	3,220
Professional fees and other offering costs		2,590
Repayment of debt		33,000
Distribution to Crosstex Holdings		2,500
Working capital		4,690
Total use of proceeds	$	46,000

The Crosstex Energy, L.P. partnership agreement contains specific provisions for the allocation of net earnings and losses to the partners for purposes of maintaining the partner capital accounts. Net income is allocated to the general partner based on incentive distributions earned for the period plus 2% of remaining net income.

(b) Sale of Additional Common Units

In September 2003, the Partnership completed a public offering of 1,725,000 common units at a public offering price of $35.97 per common unit. The Partnership received net proceeds of approximately $59.2 million, including an approximate $1.3 million capital contribution by its general partner in order to maintain its 2% interest. The net proceeds were used to repay borrowings outstanding under the bank credit facility of our operating partnership.

(c) Limitation of Issuance of Additional Common Units

During the subordination period, the Partnership may issue up to 1,316,500 additional common units or an equivalent number of securities ranking on a parity with the common units without obtaining unit-holder approval. The Partnership may also issue an unlimited number of common units during the subordination period for acquisitions, capital improvements or debt repayments that increase cash flow from operations per unit on a pro forma basis.

(d) Subordination Period

The subordination period will end once the Partnership meets the financial tests in the partnership agreement, but it generally cannot end before December 31, 2007. When the subordination period ends, each remaining subordinated unit will convert into one common unit and the common units will no longer be entitled to arrearages.

(e) Early Conversion of Subordinated Units

If the Partnership meets the applicable financial tests in the partnership agreement for any three consecutive four-quarter periods ending on or after December 31, 2005, 25% of the subordinated units will convert to common units. If the Partnership meets these tests for any three consecutive four-quarter periods ending on or after December 31, 2006, an additional 25% of the subordinated units will convert to common units. The early conversion of the second 25% of the subordinated units may not occur until at least one year after the early conversion of the first 25% of the subordinated units.

(f) Cash Distributions

In accordance with the partnership agreement, the Partnership must make distributions of 100% of available cash, as defined in the partnership agreement, within 45 days following the end of each quarter commencing with the quarter ending on March 31, 2003. Distributions will generally be made 98% to the common and subordinated unit-holders and 2% to the general partner, subject to the payment of incentive distributions as described below to the extent that certain target levels of cash distributions are achieved. Under the quarterly incentive distribution provisions, generally our general partner is entitled to 13% of amounts we distribute in excess of $0.50 per unit, 23% of the amounts we distribute in excess of $0.625 per unit and 48% of amounts we distribute in excess of $0.75 per unit. Incentive distributions totaling $954,000 were earned by our general partner for the year ended December 31, 2003. To the extent there is sufficient available cash, the holders of common units are entitled to receive the minimum quarterly distribution of $0.50 per unit, plus arrearages, prior to any distribution of available cash to the holders of subordinated units. Subordinated units will not accrue any arrearages with respect to distributions for any quarter.

The Partnership increased its fourth quarter distribution on its common and subordinated units to $0.75 per unit which was paid on February 13, 2004.

(8) Retirement Plans

The Partnership sponsors a single employer 401(k) plan for employees who become eligible upon the date of hire. The Partnership, as stated within the plan document, will make discretionary contributions at the end of the year. Contributions for the years ended December 31, 2003, 2002 and 2001 totaled $259,000, $198,000 and $116,000, respectively.

(9) Employee Incentive Plans

(a) Long-Term Incentive Plan

In December 2002, the Partnership's managing general partner adopted a long-term incentive plan for its employees, directors, and affiliates who perform services for the Partnership. The plan currently permits the grant of awards covering an aggregate of 700,000 common units, 233,000 of which may be awarded in the form of restricted units and 467,000 of which may be awarded in the form of unit options. The plan is administered by the compensation committee of the managing general partner's board of directors.

(b) Restricted Units

A restricted unit is a "phantom" unit that entitles the grantee to receive a common unit upon the vesting of the phantom unit, or in the discretion of the compensation committee, cash equivalent to the value of a common unit. In addition, the restricted units will become exercisable upon a change of control of the Partnership, its general partner, or managing general partner.

The restricted units are intended to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of the common units. Therefore, plan participants will not pay any consideration for the common units they receive and the Partnership will receive no remuneration for the units.

In May 2003, 48,000 restricted units were issued to senior management under the long-term incentive plan with an intrinsic value of $1,247,000. In September 2003, 1,075 restricted units with an intrinsic value of $39,000 were issued to a director, at his election, for his 2003 annual director fee. These restricted units vest over a five-year period and the intrinsic value of the units is amortized into stock-based compensation expense over the vesting period. The Partnership recognized stock-based compensation expense of $197,000 related to the amortization of these restricted units in 2003.

(c) Unit Options

Unit options will have an exercise price that, in the discretion of the compensation committee, may be less than, equal to or more than the fair market value of the units on the date of grant. In general, unit options granted will become exercisable over a period determined by the compensation committee. In addition, unit options will become exercisable upon a change in control of the Partnership, or its general partner, or managing general partner.

A summary of the unit option activity for the year ended December 31, 2003 and the period December 17, 2002 through December 31, 2002 is provided below:

	December 31, 2003			December 31, 2002		
	Number of units		Weighted average exercise price	Number of units		Weighted average exercise price
Outstanding, beginning of period	175,000	$	20.00	—		—
Granted	147,386	$	21.22	175,000	$	20.00
Exercised	—		—	—		—
Forfeited	(750)	$	(20.00)	—		—
Outstanding, end of period	321,636	$	20.56	175,000	$	20.00
Options exercisable at end of period	71,667	$	20.00	—		
Weighted average fair value of options granted		$	2.56		$	1.15

Outstanding options have exercise prices ranging from $20.00 to $36.29 per unit and remaining contractual lives of 9 to 10 years at December 31, 2003.

The Partnership accounts for option grants in accordance with APB No. 25, *Accounting for Stock Issued to Employees* and follows the disclosure only provision of SFAS No. 123, *Accounting for Stock-based Compensation*. In September 2003, two directors elected to receive options to purchase 5,376 common units (in aggregate) in the Partnership for their 2003 annual director fees. The options vest over a three-year period with an exercise price of $23.25 per common unit. Since the exercise price was below the market price on the grant date, the Partnership recorded stock-based compensation of $27,000 in 2003 to recognize the vesting of a portion of such options during 2003.

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

Crosstex Energy, Inc. has one stock-based compensation plan, the 2000 Stock Option Plan. CEI 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 the plan. In accordance with APB No. 25, compensation is recorded to the extent the fair value of the stock exceeds the exercise price of the option at the measurement date. In addition, compensation expense is recorded for variable options based on the difference between fair value of the stock or unit and exercise price of the options at period end. Compensation expense of $5,041,000, $41,000, and $0 was recognized in 2003, 2002, and 2001, respectively, related to CEI's stock options. Stock based compensation associated with the CEI option plan is recorded by the Partnership since CEI has no operating activities other than its interest in the Partnership.

A summary of the status of the 2000 Stock Option Plan as of December 31, 2003 and 2002, is presented in the table below (all amounts have been adjusted to reflect the two-for-one stock split made by CEI in connection with its January 2004 initial public offering):

	December 31, 2003			December 31, 2002		
	Shares		Weighted average exercise price	Shares		Weighted average exercise price
Outstanding, beginning of period	1,040,500	$	5.39	681,000	$	5.16
Granted	—		—	372,500		5.95
Exercised	(176,110)		5.20	—		—
Forfeited	(2,000)		6.00	(13,000)		6.00
Outstanding, end of period	862,390		5.42	1,040,500		5.39
Options, exercisable at period end	711,213	$	5.29	577,006	$	5.18
Fair value of $5 options granted			—		$	1.59
Fair value of $6 options granted			—		$	0.70
Fair value of $7 options granted			—		$	0.46

All options outstanding have an exercise price ranging from $5 to $7 at December 31, 2003.

CEI modified certain outstanding options attributable to its common shares in the first quarter of 2003, which allowed 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 CEI options which were modified was approximately 182,000. These modified options have been accounted for using variable accounting as of the option modification date. The Partnership accounted for the modified options as variable options until the holders elect to cash out the options or the election to cash out the options lapsed. CEI is responsible for paying the intrinsic value of the options for the holders who elect to cash out their options. December 31, 2003 was the last valuation date that a holder of modified options could elect the cash-out alternative. Accordingly, effective January 1, 2004, the remaining modified options will be accounted for as fixed 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 $5.0 million related to the variable options for the year ended December 31, 2003.

(e) Earnings per unit and anti-dilutive computations

Basic earnings per unit was computed by dividing net income, by the weighted average number of limited partner units (including restricted units) outstanding for the year ended December 31, 2003 and for the period December 17, 2002 through December 31, 2002. The computation of diluted earnings per unit further assumes the dilutive effect of unit options.

The following are the unit amounts used to compute the basic and diluted earnings per limited partner unit for the year ended December 31, 2003 and for the period December 17, 2002 through December 31, 2002 (in thousands, except per unit amounts):

	Year Ended December 31, 2003	December 17, 2002-December 31, 2002
Basic earnings per unit:		
Weighted average limited partner units outstanding	7,876	7,300
Dilutive earnings per unit:		
Weighted average limited partner units outstanding	7,876	7,300
Dilutive effect of exercise of options outstanding	104	10
Dilutive units	7,980	7,310

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

(10) Fair Value of Financial Instruments

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

	2003		2002	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(Restated)		(Restated)	
	(in thousands)			
Cash and cash equivalents	$ 166	$ 166	$ 1,308	$ 1,308
Trade accounts receivable and accrued revenues	134,775	134,775	105,549	105,549
Fair value of derivative assets	4,080	4,080	3,102	3,102
Accounts payable, drafts payable and accrued gas purchases	136,671	136,671	113,198	113,198
Long-term debt	60,750	60,750	22,550	22,550
Fair value of derivative liabilities	2,278	2,278	4,458	4,458

The carrying amounts of the Partnership's cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the short-term maturities of these assets and liabilities.

The Partnership's long-term debt was comprised of borrowings under a revolving credit facility totaling $20.0 million and $21.75 million as of December 31, 2003 and 2002, respectively, which accrues interest under a floating interest rate structure. Accordingly, the carrying value of such indebtedness approximates fair value for the amounts outstanding under the credit facility. As of December 31, 2003, the Partnership also had borrowings totaling $40 million under senior secured notes with a weighted average interest rate of 6.93%. The carrying amount of these borrowings approximates the fair value based on market conditions as of December 31, 2003.

The fair value of derivative contracts included in assets or liabilities for risk management activities represents the amount at which the instruments could be exchanged in a current arms-length transaction.

(11) 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.

The fair value of derivative assets and liabilities, excluding the interest rate swap, are as follows (in thousands):

	December 31	
	2003	2002
Fair value of derivative assets—current	$ 4,080	$ 2,947
Fair value of derivative assets—long term	—	155
Fair value of derivative liabilities—current	(2,278)	(4,006)
Fair value of derivative liabilities—long term	—	(271)
Net fair value of derivatives	$ 1,802	$ (1,175)

Set forth below is the summarized notional amount and terms of all instruments held for price risk management purposes at December 31, 2003 (all quantities are expressed in British Thermal Units). The remaining term of the contracts extend no later than December 2004, with no single contract longer than 6 months. The Partnership's counterparties to hedging contracts include Williams Energy Services Company, Sempra Energy Trading Corp., Morgan Stanley Capital Group, BP Corporation, Duke Field Services, and Duke Energy Trading and Marketing. As discussed in note 2, 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.

December 31, 2003

Transaction type	Total volume	Pricing terms	Remaining term of contracts	Fair value (in thousands)
Cash Flow Hedge:				
Natural gas swaps Cash flow hedge	(2,630,000)	Fixed prices ranging from $4.01 to $6.545 settling against the various Inside FERC Index prices	January - December 2004	$ (563)
Natural gas swaps Cash flow hedge	8,314,000		January - December 2004	2,391
Total natural gas swaps Cash flow hedge				$ 1,828
Producer Services:				
Marketing trading financial swaps	910,000	Fixed prices ranging from $3.14 to $6.24 settling against the various Inside FERC Index prices	January - December 2004	$ 284
Marketing trading financial swaps	(723,000)		January - December 2004	(522)
Total marketing trading financial swaps				$ (238)
Physical offset to marketing trading transactions	(910,000)	Fixed prices ranging from $3.59 to $6.155 settling against the various Inside FERC Index prices	January - December 2004	$ (282)
Physical offset to marketing trading transactions	723,000		January - December 2004	494
Total physical offset to marketing trading transactions swaps				$ 212

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 Producer Services that are accounted for as derivative contracts held for trading purposes are included in the fair value of derivative assets and liabilities. The

Partnership estimates the fair value of all of its energy trading contracts using prices actively quoted. The estimated fair value of energy trading contracts by maturity date was as follows (in thousands):

	Maturity periods			
	Less than one year	One to two years	Two to three years	Total fair value
December 31, 2003	$ (26)	—	—	(26)
December 31, 2002	$ (99)	(81)	—	(180)

Termination of Enron Positions

On December 2, 2001, Enron Corp. and certain subsidiaries, including Enron North America Corp. (Enron), each filed voluntary petitions for relief under Chapter 11 of Title 11 of the United States Bankruptcy Code. Enron failed to make timely payment of approximately $3.9 million for physical deliveries of gas in 2001. This amount remained outstanding as of December 31, 2002. Additionally, the Partnership had entered into natural gas hedging and physical delivery contracts with Enron. According to the terms of the contracts, Enron is liable to the Partnership for the mark-to-market value of all contracts outstanding on the date the Partnership exercised its termination right under the contracts, which totaled approximately $4.6 million and which was recorded as a receivable from Enron. The Partnership has accounted for these contracts as energy trading contracts whereby changes in fair value of the fixed price purchase and sales commitments are recognized in earnings.

The Partnership had offsets to the above amounts totaling approximately $0.3 million, resulting in a net amount of $8.2 million receivable from Enron at December 31, 2001. Due to the uncertainty of future collections, a charge and related allowance for 70% of the net receivable, or $5.7 million, was recorded at December 31, 2001. The 30% recovery rate was management's best estimate based on market transactions when the financial statements were issued. No balance is reflected at December 31, 2002 as the receivable was transferred to CEI in conjunction with the Partnership's initial public offering in December 2002.

For the year ended December 31, 2001, the Partnership recorded a loss on energy trading contracts related to natural gas marketing of $5.7 million, substantially all of which related to estimated losses on claims from Enron. This loss was partially offset by gains of $1.9 million on energy trading contracts which physically settled during 2001.

(12) Transactions with Related Parties

General and Administrative Expense Cap

The Partnership had a $6.0 million annual ($1.5 million quarterly) general and administrative cap for the twelve-month period ended in December 2003, per the partnership agreement. CEI bore the cost of any excess general and administrative expenses. During the year ended December 31, 2003, the Partnership had excess expenses of approximately $3.5 million. The general partner is also reimbursed for direct charges it incurs on behalf of partnership business development activities. Such charges totaled $0.8 million for the year ended December 31, 2003 and are included in general and administrative expenses.

Camden Resources, Inc.

The Partnership treats gas for, and purchases gas from, Camden Resources, Inc. (Camden). Camden is an affiliate of the Partnership by way of equity investments made by Yorktown in Camden. During the years ended December 31, 2003, 2002 and 2001, the Partnership purchased natural gas from Camden in the amount of approximately $8,416,000, $10,076,000, and $17,300,000, respectively, and received approximately $190,000, $399,000, and $737,000 in treating fees from Camden.

Crosstex Pipeline Partners, L.P.

The Partnership had related-party transactions with Crosstex Pipeline Partners, L.P. (CPP), as summarized below:

- During the years ended December 31, 2003, 2002 and 2001, the Partnership bought natural gas from CPP in the amount of approximately $8.2 million, $3.4 million and $6.5 million and paid for transportation of approximately $41,000, $27,500 and $31,000, respectively, to CPP.
- During the years ended December 31, 2003, 2002 and 2001, the Partnership received a management fee from CPP in the amount of approximately $125,000, $125,000 and $125,000, respectively.
- During the years ended December 31, 2003, 2002 and 2001, the Partnership received distributions from CPP in the amount of approximately $104,000, $90,000 and $152,000, respectively.

Crosstex Denton County Gathering J.V.

- During the year ended December 1, 2003, the Partnership received a management fee from Crosstex Denton County Gathering J.V. (CDC) of $110,000. Also, see Note (4) for a discussion of loans related to CDC.

(13) Commitments and Contingencies

(a) Leases

Leased office space and equipment have remaining non-cancelable lease terms in excess of one year. The following table summarizes our remaining non-cancelable future payments under operating leases as of December 31, 2003 (in thousands):

2004	$	1,228
2005		1,091
2006		960
2007		811
2008		684
Thereafter		852
	$	5,626

Operating lease rental expense in the years ended December 31, 2003, 2002 and 2001, was approximately $1,812,000, $951,000, and $1,200,000, respectively.

(b) Employment Agreements

Each member of senior management of the Partnership is a party to an employment contact 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.

(c) Environmental Issues

The Partnership acquired two assets from DEFS in June 2003 that have environmental contamination, including a gas plant in Montgomery County near Conroe, Texas and a compressor station near Cadeville, Louisiana. At both of these sites, contamination from historical operations has been identified at levels that exceed the applicable state action levels. Consequently, site investigation and/or remediation are underway to address those impacts. The estimated remediation cost for the Conroe plant site is currently estimated to be approximately $3.2 million, and the remediation cost for the Cadeville site is currently estimated to be approximately $1.2 million. Under the purchase agreement, DEFS has retained liability for cleanup of both the Conroe and Cadeville sites. Moreover, the remediation costs associated with the Conroe site will be covered by agreements with TRC Companies and AIG. Therefore, the Partnership does not expect to incur any material environmental liability associated with the Conroe or Cadeville sites.

(d) Other

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

The Partnership receives notices from pipeline companies from time to time of gas volume allocation corrections related to gas deliveries on their pipeline systems. These allocation corrections normally have little impact on the Partnership's gross margin because the Partnership balances its purchases and sales in the pipelines and both the purchase and sale on the pipeline system require corrections. At December 31, 2003, a subsidiary of the Partnership was involved in a dispute related to one such allocation correction with a pipeline company and a customer on that pipeline. In reallocating previous settled deliveries, the pipeline company billed the Partnership's subsidiary for approximately $1.2 million of gas deliveries, that occurred in the period from December, 2000 through February, 2001. The Partnership's subsidiary, in turn, billed its customer who was overpaid due to the allocation error. The customer is disputing its liability for such amount, asserting that the corrected billing was untimely. The allocation error occurred prior to the Partnership's acquisition of the subsidiary involved in the dispute. The Partnership has an indemnity from the seller of the subsidiary for liabilities arising prior to the acquisition date. As of December 31, 2003, the Partnership has recorded a receivable of $1.2 million in other current receivables and a liability of $1.2 million in other current liabilities related to this allocation correction. The Partnership believes the customer's dispute of the receivable is without merit, and further believes that it is protected against loss by its right to indemnification.

(14) 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 located in south Texas, the Seminole plant located in Gaines County, Texas and various other small systems. Also included in the Midstream division are the Partnership's Producer Services operations (note 2(i)). The operations in the Midstream segment are similar in the nature of the products and services, the nature of the production processes, the type of customer, the methods used for distribution of products and services and the nature of the regulatory environment. The Treating division generates fees from its plants either through volume-based treating contracts or 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. 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. Inter-segment sales are at cost.

Summarized financial information concerning the Partnership's reportable segments is shown in the following table. There are no other significant non-cash items.

	Midstream	Treating	Totals
		(in thousands)	
Year ended December 31, 2003 (restated):			
Sales to external customers	$ 993,140	$ 20,523	$ 1,013,663
Inter-segment sales	6,893	(6,893)	—
Interest expense	(3,323)	(69)	(3,392)
Stock-based compensation	4,276	1,069	5,345
Depreciation and amortization	10,326	2,942	13,268
Segment profit (loss)	13,049	2,177	15,226
Segment assets (restated)	323,527	42,523	366,050
Capital expenditures	28,728	10,275	39,003
Year ended December 31, 2002 (restated):			
Sales to external customers (restated)	$ 437,432	$ 14,817	$ 452,249
Inter-segment sales	4,073	(4,073)	—
Interest expense	(2,327)	(390)	(2,717)
Impairments	—	4,175	4,175
Depreciation and amortization	5,738	2,007	7,745
Segment profit (loss) (restated)	1,613	(1,269)	344
Segment assets (restated)	199,803	33,382	233,185
Capital expenditures	11,154	3,391	14,545
Year ended December 31, 2001:			
Sales to external customers	$ 362,673	$ 24,353	$ 387,026
Inter-segment sales	10,633	(10,633)	—
Interest expense	1,840	413	2,253
Impairments	2,873	—	2,873
Depreciation and amortization	4,534	1,567	6,101
Segment profit (loss)	(4,607)	689	(3,918)
Segment assets	137,303	31,073	168,376
Capital expenditures	6,484	16,201	22,685

(15) Quarterly Financial Data (Unaudited)

Summarized un-audited quarterly financial data is presented below.

Previously Reported:

	First	Second	Third	Fourth	Total
	(in thousands, except per unit amounts)				
2003					
Revenues	$ 250,570	$ 229,252	$ 283,198	$ 250,643	$ 1,013,663
Operating income	1,204	5,479	5,158	6,598	18,439
Net income (loss)	832	4,975	3,888	5,531	15,226
Earnings per common unit-basic	$ 0.11	$ 0.66	$ 0.44	$ 0.56	$ 1.80
Earnings per common unit-diluted	$ 0.11	$ 0.65	$ 0.43	$ 0.54	$ 1.77
2002					
Revenues	$ 80,993	$ 126,480	$ 114,611	$ 130,409	$ 452,493
Operating income(4)	4,681	5,468	6,182	5,945	22,276
Net income (loss)	(252)	224	1,485	545	2,002

As Restated(3):

	First	Second	Third	Fourth	Total
2003					
Revenues	$ 250,570	$ 229,252	$ 283,198	$ 250,643	$ 1,013,663
Operating income	1,204	5,479	5,158	6,598	18,439
Net income (loss)	832	4,975	3,888	5,531	15,226
Earnings per common unit-basic	$ 0.11	$ 0.66	$ 0.44	$ 0.56	$ 1.80
Earnings per common unit-diluted	$ 0.11	$ 0.65	$ 0.43	$ 0.54	$ 1.77
2002					
Revenues	$ 80,811	$ 126,418	$ 114,611	$ 130,409	$ 452,249
Operating income	137	(26)	2,120	781	3,012
Net income (loss)	(626) (1)	(988)	1,485	473(1)(2)	344

(1) Included in the 2002 first and fourth quarter results are impairment charges of $3.2 million and $1.0 million, respectively, principally related to the impairment of certain intangibles related to gas plants.

(2) Earnings per basic and diluted common unit was $0.04 for the period from December 17, 2002 (date of initial public offering) through December 31, 2002.

(3) Restated to reflect the correction of clerical errors that resulted in certain reconciling items relating to 2002 not being properly cleared. See Note 2 to the consolidated financial statements. The adjustments resulted in a reduction in net income for the year ended December 31, 2002 by $1.7 million and a reduction in partners' equity as of December 31, 2002 and 2003 by $1.7 million.

(4) As previously reported, operating income was calculated as total revenues less purchased gas costs and operating expenses. As restated, these numbers reflect those shown on the operating (loss) income line on the consolidated statement of operations, to conform with the 2003 presentation.

(16) Subsequent Event (Unaudited)

The Partnership entered into a definitive agreement on February 13, 2003 for the acquisition of the LIG Pipeline Company and its subsidiaries (LIG) from American Electric Power for $76.2 million. The acquisition will increase the Partnership's pipeline miles by approximately 2,000 miles of pipeline, to a total of 4,500 pipeline miles. Closing, which is subject to completion of certain conditions, is expected to occur within 90 days. The Partnership will finance through borrowings under the Partnership's existing bank credit facility, issuance of additional senior note or other financing alternatives.

CROSSTEX ENERGY, L.P.

(Successor to Crosstex Energy Services, Ltd.)

(In thousands)

	Balance at beginning of period	Charged to costs and expenses	Deductions	Balance at end of period
Year ended December 31, 2003				
Allowance for doubtful accounts	—	—	—	—
Year ended December 31, 2002				
Allowance for doubtful accounts	$ 5,776	—	(5,776) (a)	—
Year ended December 31, 2001				
Allowance for doubtful accounts	—	$ 5,776	—	$ 5,776

(a) The Enron receivable was contributed to Crosstex Energy, Inc. at the time of the initial public offering and therefore the related allowance is no longer recorded on the books of the Partnership.

QuickLinks -- Click here to rapidly navigate through this document

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

The Partners
Crosstex Energy, L.P.:

We consent to the incorporation by reference in the registration statement (No. 333-107025) on Form S-8 and the registration statement (No. 333-116538) on Form S-3 of Crosstex Energy, L.P. of our report dated February 26, 2004 except as to note 2, which is as of July 28, 2004, with respect to the consolidated balance sheets of Crosstex Energy, L.P. as of December 31, 2003 and 2002, and the related consolidated statements of operations, changes in partners' equity, comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2003, and all related financial statement schedules, which report appears in the December 31, 2003, annual report on Form 10-K/A of Crosstex Energy, L.P. Our report refers to a change in accounting for derivatives and a change in the method of amortizing goodwill. Our report also refers to the Company restating its financial statements.

/s/ KPMG LLP
Dallas, Texas
August 5, 2004

Exhibit 31.1

CERTIFICATION

I, Barry E. Davis, certify that:

1. I have reviewed this annual report on Form 10-K/A 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: August 9, 2004	/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 31.2

CERTIFICATIONS

I, William W. Davis, certify that:

1. I have reviewed this annual report on Form 10-K/A 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: August 9, 2004

/s/ WILLIAM W. DAVIS

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

QuickLinks -- Click here to rapidly navigate through this document

Exhibit 32.1

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

In connection with the Annual Report of Crosstex Energy, L.P. (the "Registrant") on Form 10-K/A for the fiscal year ending December 31, 2003 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each of the undersigned, Barry E. Davis, Chief Executive Officer of Crosstex Energy GP, LLC, and William W. Davis, Chief Financial Officer of Crosstex Energy GP, LLC, certifies, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

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

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

/s/ BARRY E. DAVIS

Barry E. Davis
Chief Executive Officer

August 9, 2004

/s/ WILLIAM W. DAVIS

William W. Davis
Chief Financial Officer

August 9, 2004

A signed original of this written statement required by Section 906 has been provided to the Registrant and will be retained by the Registrant and furnished to the Securities and Exchange Commission or its staff upon request. The foregoing certification is being furnished to the Securities and Exchange Commission as an exhibit to the Report.