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SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

Form 10-K

☒ **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.

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DESCRIPTION

CROSSTEX ENERGY, L.P.

PART I

Item 1. *Business*

General

Crosstex Energy, L.P. is a publicly traded Delaware limited partnership, formed in July 2002 in connection with its initial public offering, which was completed in December 2002. Our Common Units are listed on the NASDAQ National Market. Our business activities are conducted through our subsidiary, Crosstex Energy Services, L.P., a Delaware limited partnership (the "Operating Partnership") and the subsidiaries of the Operating Partnership. Our executive offices are located at 2501 Cedar Springs, Suite 600, Dallas, Texas 75201, and our telephone number is (214) 953-9500. In this report, the terms "Partnership" and "Registrant," as well as the terms "our," "we," and "its," are sometimes used as abbreviated references to Crosstex Energy, L.P. itself or Crosstex Energy, L.P. and its consolidated subsidiaries, including the Operating Partnership.

We are a rapidly growing independent midstream energy company engaged in the gathering, transmission, treating, processing and marketing of natural gas. We connect the wells of natural gas producers in our market areas to our gathering systems, treat natural gas to remove impurities to ensure that it meets pipeline quality specifications, process natural gas for the removal of natural gas liquids or NGLs, transport natural gas and ultimately provide an aggregated supply of natural gas to a variety of markets. We purchase natural gas from natural gas producers and other supply points and sell that natural gas to utilities, industrial consumers, other marketers and pipelines and thereby generate gross margins based on the difference between the purchase and resale prices. In addition, we purchase natural gas from producers not connected to our gathering systems for resale and sell natural gas on behalf of producers for a fee.

Our major assets include over 2,500 miles of natural gas gathering and intrastate transmission pipelines, three natural gas processing plants connected to our gathering systems with a total NGL production capacity of 289,800 gallons per day and 61 natural gas treating plants. Our gathering systems consist of a network of pipelines that collect natural gas from points near producing wells and transport it to larger pipelines for further transmission. Our transmission pipelines primarily receive natural gas from our gathering systems and from third party systems and deliver natural gas to industrial end-users, utilities and other pipelines. Our processing plants remove NGLs from a natural gas stream and fractionate, or separate, the NGLs into separate NGL products, including ethane, propane, mixed butanes and natural gasoline. Our natural gas treating plants, located largely in the Texas Gulf Coast area, remove impurities from natural gas prior to delivering the gas into pipelines to ensure that it meets pipeline quality specifications.

Set forth in the table below is a list of our significant acquisitions since January 2000.

Acquisition	Acquisition Date	Purchase Price (in thousands)	Asset Type	Average Throughput at Time of Acquisition (MMBtu/d)	Average Throughput for Year Ended December 31, 2003 (MMBtu/d)
Provident City Plant	February 2000	$ 350	Treating plants	2,200	23,000
Will-O-Mills (50%)	February 2000	2,000	Treating plants	11,700	8,500
Arkoma Gathering System	September 2000	10,500	Gathering pipeline	12,000	13,000
Gulf Coast System	September 2000	10,632	Gathering and transmission pipeline	117,000	85,000(1)
CCNG Acquisition	May 2001	30,003	Gathering and transmission pipeline and processing plant	272,000	414,000
Pettus Gathering System	June 2001	450	Gathering system	—	—
Millennium Gas Services	October 2001	2,124	Treating assets	—	—
Hallmark Lateral	June 2002	2,300	Pipeline segment	—	57,000
Pandale System	June 2002	2,156	Gathering pipeline	16,000	13,000
KCS McCaskill Pipeline	June 2002	250	Pipeline segment	—	—
Vanderbilt System	December 2002	12,000	Transmission pipeline	32,000	49,000(1)
Will-O-Mills (50%)	December 2002	2,200	Treating plant	9,700	8,500
DEFS Acquisition	June 2003	68,124	Gathering and transmission systems, processing plants and pipeline systems	129,000	127,000(2)

(1) Certain Gulf Coast customers are now provided service through the Vanderbilt system.

(2) Represents average throughput from the acquisition date, June 30, 2003, through December 31, 2003.

We have two operating segments, Midstream and Treating. 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. See Note 13 to the consolidated financial statements for financial information about these operating segments.

Our general partner interest is held by Crosstex Energy GP, L.P., a Delaware limited partnership. Crosstex Energy GP, LLC, a Delaware limited liability company, is Crosstex Energy GP, L.P.'s general partner. Crosstex Energy GP, LLC manages our operations and activities and employs our officers.

References in this report to "our predecessor" refer to Crosstex Energy Services, Ltd., a Texas limited partnership, substantially all of the assets of which were transferred to the Partnership at the closing of our initial public offering.

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

Business Strategy

Our strategy is to increase distributable cash flow per unit by making accretive acquisitions of assets that are essential to the production, transportation, and marketing of natural gas; improving the profitability of our owned assets by increasing their utilization while controlling costs; accomplishing economies of scale through new construction or expansion in core operating areas; and maintaining financial flexibility to take advantage of opportunities. Our strategy is based on our expectation of a continued high level of drilling in our principal geographic areas and a process of ongoing divestitures of gas transportation and processing assets by large industry participants. We believe these two factors should present opportunities for continued expansion in our existing areas of operation as well as opportunities to acquire assets in new geographic areas that may serve as a platform for future growth. Key elements of our strategy include the following:

- *Pursuing accretive acquisitions.* We intend to use our acquisition and integration experience to continue to make strategic acquisitions of midstream assets that offer the opportunity for operational efficiencies and the potential for increased utilization and expansion of the acquired asset. We pursue acquisitions that we believe will add to existing core areas in order to capitalize on our existing infrastructure, personnel, and producer and consumer relationships. We also examine opportunities to establish new core areas in regions with significant natural gas reserves and high levels of drilling activity or with growing demand for natural gas. We plan to establish new core areas primarily through the acquisition of key assets that will serve as a platform for further growth both through additional acquisitions and the construction of new assets. A recent example of establishing a new core area includes the Mississippi pipeline system acquired as part of the DEFS acquisition. This system provides us with a platform to develop a significant presence in the south central Mississippi area.

- *Improving existing system profitability.* After we acquire or construct a new system, we begin an aggressive effort to market services directly to both producers and end users in order to connect new supplies of natural gas, improve margins, and fully utilize the system's capacity. Many of our recently acquired systems have excess capacity that provides us opportunities to increase throughput with minimal incremental cost. As part of this process, we focus on providing a full range of services to small and medium size independent producers and end users, including supply aggregation, transportation and hedging, which we believe provides us with a competitive advantage when we compete for sources of natural gas supply. Additionally, we emphasize increasing the percentage of our natural gas sales directly to end users, such as industrial and utility consumers in an effort to increase our operating margins. For the year ended December 31, 2003, approximately 58% of our on-system natural gas sales were to industrial end users and utilities.

- *Undertaking construction and expansion opportunities.* We leverage our existing infrastructure and producer and customer relationships by constructing and expanding systems to meet new or increased demand for our gathering, transmission, treating, processing and marketing services. These projects include expansion of existing systems and construction of new facilities. As an example, we enhanced the Gregory system by acquiring the Koch Ingleside Pipeline and connecting directly to a major end user customer. Our 2002 acquisition of the Hallmark Lateral facilitated the establishment of connections between our Corpus Christi and our Gulf Coast systems which has increased our flexibility in balancing gas supply and market requirements throughout the regions covered. In August 2003, we expanded the capacity of our Gregory processing plant from 99,900 MMBtu/d to 166,500 MMBtu/d, a 67% increase over its previous capacity, and began marketing the additional gas through our Corpus Christi and Gulf Coast systems.

Recent Acquisitions and Expansion

Duke Energy Field Services. In June 2003, we acquired various midstream assets located in Mississippi, Texas, Alabama and Louisiana from DEFS 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. In addition, we believe that the acquisition has increased the stability of our cash flow as operating profits from the Mississippi pipeline system are generated through purchasing, gathering, transporting and reselling natural gas which generates margins not affected by commodity prices, and a majority of the income we receives from the Seminole gas plant is based on fixed fees for carbon dioxide separation and sulfur removal.

Gregory Expansion. In August 2003, we completed an expansion of our Gregory processing plant. The expansion increased the plant capacity from approximately 99,900 MMBtu/d to 166,500 MMBtu/d, at a cost of approximately $7.0 million. In addition, we have significantly reduced our exposure to commodity prices by renegotiating a number of our commodity based contracts, where revenues were subject to fluctuating commodity prices, to fee-based contracts. See Item 2. "Properties."

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 the Partnership's 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.

Other Developments

Two-For-One Split of Limited Partnership Units. On February 26, 2004, we announced a two-for-one split on our outstanding limited partnership units. The unit split will entitle unit holders of record at the close of business on March 16, 2004 to receive one additional limited partnership unit for every unit held. All unit amounts in this Annual Report on Form 10-K reflect pre-split units.

Initial Public Offering of Crosstex Energy, Inc. Our general partner, Crosstex Energy GP, L.P., is an indirect wholly owned subsidiary of Crosstex Energy, Inc. ("CEI"). In January 2004, CEI completed an initial public offering of its common shares pursuant to which its existing shareholders, including CES management and directors, sold a portion of their common shares with public shareholders now owning 22.0% of CEI.

Our Follow-on Offering. 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 the general partner. The net proceeds were used to repay borrowings outstanding under the bank credit facility of our operating partnership.

Bank Credit Facility. In June 2003, our operating partnership, Crosstex Energy Services, L.P., entered into a new $100.0 million senior secured credit facility, which was increased to $120 million in October 2003, consisting of a $70.0 million acquisition facility and a $50.0 million working capital and letter of credit facility. As of December 31, 2003, the operating partnership had $20.0 million of

outstanding borrowings under the acquisition facility and $30.3 million of letters of credit issued under the working capital and letter of credit facility. The credit facility matures in June 2006.

Secured Secured Notes. In June 2003, the operating partnership entered into a master shelf agreement with an institutional lender pursuant to which it issued $30.0 million of senior secured notes with an interest rate of 6.95% and a maturity of seven years. In July 2003, the operating partnership issued $10.0 million of senior secured notes pursuant to the master shelf agreement with an interest rate of 6.88% and a maturity of seven years. The senior secured notes are guaranteed by the operating partnership's subsidiaries and us. The operating partnership used the net proceeds from the senior notes offering to repay indebtedness under its bank credit facility.

Midstream Division

Gathering and Transmission. Our primary Midstream assets include systems located primarily along the Texas Gulf Coast and in south-central Mississippi, which, in the aggregate, consist of approximately 2,500 miles of pipeline and three processing plants and contributed approximately 78% and 72% of our gross profit in 2003 and 2002, respectively.

- *Gulf Coast System.* The Gulf Coast system is an intrastate pipeline system consisting of approximately 484 miles of gathering and transmission pipelines with a mainline from Refugio County in south Texas running northeast along the Gulf Coast to the Brazos River in Fort Bend County near Houston. The system's gathering and transmission pipelines range in diameter from 4 to 20 inches. We acquired the Gulf Coast system in September 2000 for a purchase price of approximately $10.6 million.

  The Gulf Coast system has two supply pipeline laterals which connect to gathering systems which collect natural gas from approximately 80 receipt points and five treating and processing plants operated by third parties. This system has three delivery laterals which deliver natural gas directly to large industrial and utility consumers along the Gulf Coast. The system interconnects with multiple third party pipelines through which we may purchase volumes not gathered through our systems for resale or through which we might deliver natural gas to customers which are not connected to our system. We transport gas on the TXU Lone Star pipeline providing access for our Gulf Coast mainline system in Fort Bend County to the Katy hub, a major natural gas physical exchange that allows access to seven third party pipelines, including Kinder Morgan, TECO and Trunkline. The Gulf Coast system has a capacity of 210,600 MMBtu/d and average throughput on this system was approximately 85,000 MMBtu/d for the year ended December 31, 2003.

  We generate operating profits in our Gulf Coast system through the margins we earn by purchasing, gathering, transporting and reselling natural gas. We purchase natural gas from a producer, pipeline or marketing company and then transport and resell the gas. As of December 31, 2003, we were purchasing gas from over 70 producers primarily pursuant to month-to-month contracts and were reselling the natural gas to approximately 10 customers primarily pursuant to short-term or month-to-month arrangements. For the year ended December 31, 2003, approximately 92% of the natural gas volumes we purchased were purchased at a fixed price relative to an index and the remainder was purchased at a percentage of an index, and all the natural gas volumes we sold were sold at a fixed price relative to an index.

- *Vanderbilt System.* Our Vanderbilt system consists of approximately 200 miles of gathering and transmission pipelines located in Wharton and Fort Bend Counties near our Gulf Coast system. Natural gas is supplied to the system from over 27 receipt points. The gas had been sold to the Exxon Katy plant and, in June 2003, we reversed the flow of gas and began deliveries to the Formosa Hydrocarbons processing plant at Point Comfort, Texas. Our Vanderbilt system has a capacity of 141,700 MMBtu/d and average throughput was approximately 49,000 MMBtu/d for

  the year ended December 31, 2003. We acquired the Vanderbilt system in December 2002 for a purchase price of $12.0 million.

  All the gas in the Vanderbilt system is now sold to Formosa Hydrocarbons under a ten year agreement which began in June 2003 to supply up to 60,000 MMBtu/d. The gas is sold to Formosa at a fixed price relative to an index. Gas is purchased from approximately 15 producers, primarily pursuant to month-to-month arrangements, at over 25 receipt points. Approximately 55% percent of the gas is purchased at a percentage of an index, and the remainder is purchased at a fixed price relative to an index. We generate operating profits in the system through the margins we earn by purchasing gas from producers, then gathering, transporting and reselling the natural gas to Formosa.

- *Corpus Christi System.* The Corpus Christi system is an intrastate pipeline system consisting of approximately 295 miles of gathering and transmission pipelines and extending from supply points in south Texas to markets in the Corpus Christi area. Our gathering and transmission pipelines range in diameter from four to 20 inches. We acquired the Corpus Christi system in May 2001 in conjunction with the acquisition of the Gregory gathering system and Gregory processing plant, which we collectively refer to as the CCNG Acquisition, for an aggregate purchase price of approximately $30 million. Our Corpus Christi system had average throughput of approximately 152,000 MMBtu of gas per day at the time of its acquisition. The main lines comprising the Corpus Christi system were constructed at various times from the 1940's through the 1990's.

Natural gas is supplied to the Corpus Christi system from approximately 13 receipt points, 16 treating and processing plants and third party gathering systems and pipelines. The system interconnects with multiple third party pipelines through which we purchase volumes not gathered through our systems for resale and delivers natural gas to customers which are not connected to our system, including the Banquette hub. The Corpus Christi system has a capacity of 355,950 MMBtu/d and average throughput on this system was approximately 213,800 MMBtu/d for the year ended December 31, 2003.

In June 2002, we acquired from Florida Gas Transmission approximately 70 miles of 20 inch transmission line which allows us to access new markets within Texas and to interconnect to the Florida Gas system within Texas. We have constructed an addition to this transmission line creating a connection between our Gulf Coast system and our Corpus Christi system. This connection allows us to transport gas between our two systems, thereby reducing our dependence on third-party suppliers, move gas supplies to more favorable markets and enhance our margins. In November 2002, we completed construction of the interconnect between the Hallmark Lateral and the Florida Gas system. With this connection, we began selling gas into the Florida markets and sold approximately 57,000 MMBtu/d for the year ended December 31, 2003.

We generate operating profits in our Corpus Christi system through the margins we earn by purchasing, gathering, transporting and reselling natural gas. As of December 31, 2003, we were purchasing natural gas from approximately 35 producers generally on month-to-month or short-term arrangements. For the year ended December 31, 2003, substantially all of the natural gas volumes we purchased were purchased at a fixed price relative to an index. The Corpus Christi system transports natural gas to the Corpus Christi area where our customers include multiple major refineries and other industrial installations, as well as the local electric utility. As of December 31, 2003, we were selling gas to over 20 customers primarily pursuant to contracts that expire at various times between 2003 and 2006. For the year ended December 31, 2003, all of the natural gas volumes we sold were sold at a fixed price relative to an index.

- *Gregory Gathering System.* We acquired the Gregory processing plant and the Gregory gathering system in May 2001 in connection with the acquisition of the Corpus Christi system. The plant

and the gathering system are located north of Corpus Christi, Texas. The gathering system is connected to approximately 70 receipt points in San Patricio County, the Corpus Christi Bay area, Mustang Island, and adjacent coastal areas. The gathering system consists of approximately 297 miles of pipeline ranging in diameter from two inches to 18 inches with a total estimated throughput capacity of 222,000 MMBtu/d. The gathering system had average throughput of approximately 151,000 MMBtu/d for the year ended December 31, 2003 compared to an average throughput of approximately 76,500 MMBtu/d of gas per day at the time of its acquisition. The Gregory Gathering System was constructed in the 1980s.

We generate operating profits in our Gregory gathering system and our Gregory processing plant through the margins earned by purchasing, gathering, transporting and reselling natural gas, and through the incremental margin, if any, generated by processing the portion of the gas for which we retain the processing risk. As of December 31, 2003, we were purchasing gas from over 60 producers primarily pursuant to month-to-month contracts, and for the year ended December 31, 2003, approximately 95% of the natural gas volumes we purchased were purchased at a fixed price relative to an index and the remainder was purchased at percentage of an index.

- *Gregory Processing Plant.* Our Gregory processing plant is a cryogenic turbo expander with a 210,000 gallon per day fractionator that removes liquid hydrocarbons from the liquids-rich gas produced into the Gregory gathering system. Our Gregory processing plant inlet capacity was expanded from 99,900 MMBtu/d to approximately 166,500 MMBtu/d during 2003, and average throughput was approximately 106,000 MMBtu/d for the year ended December 31, 2003. At the time of acquisition, the plant was processing approximately 43,400 MMBtu/d of gas per day. The Gregory processing plant was constructed in the 1980s and expanded and upgraded in 1998 and 2003.

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. The processed natural gas is delivered to multiple customers at prices based on a fixed price relative to a monthly index. Since we extract Btus 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 conditioning fee for 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.

- *Arkoma Gathering System.* We acquired the Arkoma gathering system, located in the Southeastern region of Oklahoma, in September 2000 for $10.5 million. In addition, since acquiring this system, we have acquired the Shawnee extension, consisting of 15 miles of gathering pipelines extending through additional supply areas in this region. The Arkoma gathering system when acquired was approximately 84 miles in length and included a 3,700 horsepower compressor station. With the addition of the Shawnee extension and additional well connections, the system is now approximately 100 miles in length and ranges in diameter from 2

to 10 inches. This low-pressure system gathers gas from approximately 170 wells to three compressor stations for discharge to a mainline transmission pipeline. This system has a capacity of 21,400 MMBtu/d and average throughput was approximately 13,000 MMBtu/d for the year ended December 31, 2003.

We generate a margin for gathering and transporting gas in the Arkoma gathering system equal to a percentage of the proceeds from the sale of the natural gas to the mainline transmission pipeline into which we deliver. We take title to the gas at the point of receipt into the gathering system, with payment based upon an allocation of the metered volume sold into the mainline transmission facilities of our customer with the producer sharing their pro rata portion of the fuel costs for the compression and the removal of water from the natural gas stream.

- *Mississippi Pipeline System.* We acquired the Mississippi pipeline system from DEFS in June 2003 in connection with the DEFS acquisition. The Mississippi pipeline system is located in 15 counties of south Mississippi spanning from the city of Jackson in the northwest to Hattiesburg in the southeast. The system has wellhead supply connections in most of the gas fields in the counties of operation—primarily Jasper, Jefferson Davis, Lawrence, Marion and Simpson counties.

The system delivers natural gas through direct market connections to utilities and industrial end users. The pipeline system consists of approximately 638 miles of pipeline ranging in diameter from four to 20 inches with a total estimated capacity of 198,500 MMBtu/d. Average throughput on this system was approximately 79,000 MMBtu/d for the year ended December 31, 2003. The system was constructed in the 1970s.

We generate operating profits in our Mississippi pipeline system by purchasing, gathering, transporting and reselling natural gas. We purchase gas from approximately 50 producers at the delivery points into the system and gas is sold to approximately 15 customers. The majority of contracts provide that natural gas volumes are purchased at a fixed price relative to an index.

- *Seminole Gas Processing Plant.* 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. The plant also receives 50% of the NGLs produced by the plant. We have entered into a one-year contract with Duke Energy NGL Services, L.P. to market our NGLs on our behalf. We 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. The plant had capacity of 150,000 Mcf/d at the time of acquisition. The recently completed expansion increased capacity by 60,000 Mcf/d, increasing total capacity to 210,000 Mcf/d. Average throughput for the plant was approximately 144,000 Mcf/d for the last six months of 2003. The plant was constructed in the 1980s.

- *Conroe Gas Plant And Gathering System.* We acquired the Conroe gas plant and gathering system in June 2003 in connection with the DEFS asset acquisition. Located in Montgomery County, Texas, the Conroe gas plant is a cryogenic gas processing plant with 10 miles of gathering pipelines located within the Conroe Field Unit, which is operated by ExxonMobil. The plant gathers low pressure and high pressure natural gas through contracts with over 20 producers. The plant has outlet natural gas connections to Kinder Morgan Texas Pipeline, L.P. and Copano Field Services. Recovered NGLs are delivered into the Chaparral NGL pipeline. The plant has a capacity of 70,265 MMBtu/d and average throughput on this system was approximately 26,000 MMBtu/d for the year ended December 31, 2003. The Conroe gas plant was constructed in the 1930s.

We generate operating profits at our Conroe gas plant from one customer primarily from compression and processing fees and from retaining 40% of the NGLs from the recycled lift gas.

- *Alabama Pipeline System.* We acquired the Alabama pipeline system in June 2003 in connection with the DEFS asset acquisition. The system is located in Fayette, Lamar, Picken and Tuscaloosa Counties in west-central Alabama. The system gathers coalbed methane gas from the Black Warrior Basin and other conventional wells. The system is a series of three natural gas gathering and transmission systems consisting of approximately 125 miles of four to twelve inch pipeline with an estimated capacity of 72,300 MMBtu/d. One supplier to the system accounted for over half of the gas gathered. The gas is delivered primarily to industrial end users. Average throughput on this system was approximately 14,000 MMBtu/d for the year ended December 31, 2003. The system was constructed in the 1970's.

  We generate operating profits in our Alabama pipeline system by gathering, transporting and reselling natural gas. All gas is purchased at the delivery points into the system. The majority of the contracts are priced at a fixed basis to an area index and we sell gas to approximately five customers.

- *Other Systems.* We own several small gathering systems totaling approximately 135 miles, including the Manziel system in Wood County, Texas, the San Augustine system in San Augustine County, Texas, the Freestone Rusk system in Freestone County, Texas, the Jack Starr and North Edna systems in Jackson County, Texas and the Cadeville and Aurora Centana systems in Louisiana. Through Crosstex Pipeline Partners, a limited partnership of which we are the co-general partner, we own a 28% interest in five gathering systems in east Texas, totaling 64 miles with a combined capacity of 119,000 MMBtu/d. We also own five industrial bypass systems each of which supplies natural gas directly from a pipeline to a dedicated customer. The combined volumes for these five industrial bypass systems was approximately 4,200 MMBtu/d for the year ended December 31, 2003. In addition to these systems, we own various smaller gathering and transmission systems located in Texas, New Mexico and Louisiana.

Producer Services. 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. Profits from energy trading activities for the year ended December 31, 2003 and 2002 were $1.9 million and $2.7 million, respectively.

Our business strategy includes developing relationships with natural gas producers to facilitate the purchase of their production on a long-term basis. We believe that this business also provides us with strategic insights and valuable market intelligence which may impact our expansion and acquisition strategy.

We offer to our customers the ability to hedge their purchase or sale price by agreeing to sell to us or to purchase from us volumes of natural gas. This risk management tool enables our customers to reduce pricing volatility associated with the sale and purchase of natural gas. When we agree to purchase or sell natural gas from a customer, we contemporaneously execute a contract for the sale or purchase of such natural gas or we enter into an offsetting obligation using futures contracts on the New York Mercantile Exchange or by using over-the-counter derivative instruments with third parties.

Treating Division

We operate treating plants which remove carbon dioxide and hydrogen sulfide from natural gas before it is delivered into transportation systems to ensure that it meets pipeline quality specifications.

Our treating division contributed approximately 22% and 27% of our gross margin in 2003 and 2002, respectively. Our treating business has grown from 35 plants in operation at December 31, 2002 to 52 plants in operation at December 31, 2003.

As of December 31, 2003, we owned 61 treating plants, 41 of which were operated by our personnel, 11 of which were operated by producers, and 9 of which were held in inventory. We entered the treating business in 1998 with the acquisition of WRA Gas Services and we are now one of the largest gas treating operations in the Texas Gulf Coast. The treating plants remove carbon dioxide and hydrogen sulfide from natural gas before it is introduced to transportation systems to ensure that it meets pipeline quality specifications. Natural gas from certain formations in the Texas Gulf Coast, as well as other locations, is high in carbon dioxide. The majority of our active plants are treating gas from the Wilcox and Edwards formations in the Texas Gulf Coast, both of which are deeper formations that are high in carbon dioxide. Our active treating facilities include 47 amine plants and five hydrogen sulfide scavenger installations. In cases where producers pay us to operate the treating facilities, we either charge a fixed rate per Mcf of natural gas treated or charge a fixed monthly fee.

In addition to our treating plants, we have three gathering systems with an aggregate of 43 miles of gathering pipeline located in Val Verde, Crockett, Dewitt and Live Oak counties, Texas that are connected to approximately 73 producing wells. These gathering systems are connected to three of our treating plants. The diameter of these gathering pipelines ranges from two to six inches. These gathering assets in the aggregate have a capacity of 61,000 MMBtu/d and average throughput was approximately 20,800 MMBtu/d for the year ended December 31, 2003. In cases where we both gather and treat natural gas, our fee is generally based on throughput.

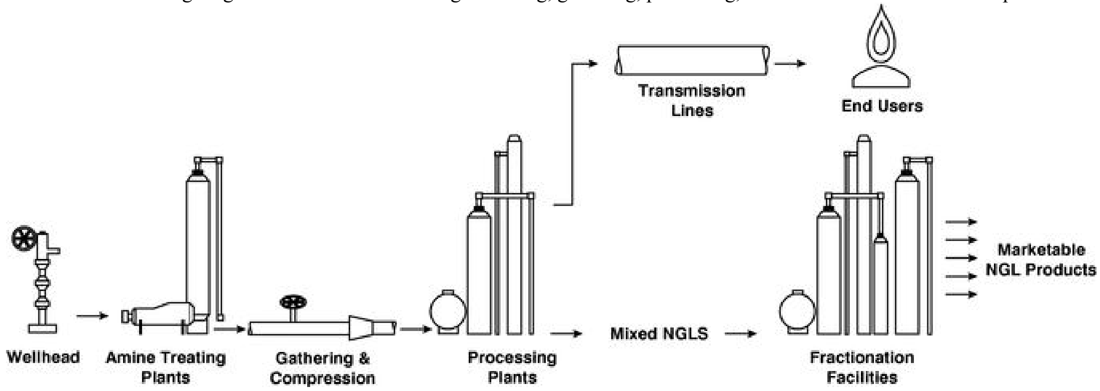
A component of our strategy is to purchase used plants and then refurbish and repair them at our shop and seven-acre yard in Victoria, Texas and our 14-acre yard in Odessa, Texas. We believe that we can purchase used plants and recondition them at a significant cost savings to purchasing new plants. We have an inventory of plants of varying sizes which can be deployed after refurbishment. We also mount most of the plant equipment on skids allowing them to be moved in a timely and cost efficient manner. At such time as our active plants come offline, the Partnership will put them in our inventory pending redeployment. We believe our plant inventory gives us an advantage of several weeks in the time required to respond to a producer's request for treating services.

Treating process. The amine treating process involves a continuous circulation of a liquid chemical called amine that physically contacts with the natural gas. Amine has a chemical affinity for hydrogen sulfide and carbon dioxide that allows it to absorb the impurities from the gas. After mixing, gas and amine are separated and the impurities are removed from the amine by heating. Treating plants are sized by the amine circulation capacity in terms of gallons per minute. The size range of the 52 plants in operation is 3.5 to 300 gallons per minute, and the size range of the 9 plants in inventory is 3.5 to 1,000 gallons per minute.

Hydrogen sulfide scavenger facilities use a liquid or solid chemical that reacts with hydrogen sulfide thereby removing it from the gas. Used chemicals are disposed of and cannot be regenerated as amine can. The facilities are primarily vertical towers mounted on concrete foundations. As of December 31, 2003, we had two such facilities which were operated by the producer.

Industry Overview

The following diagram illustrates the natural gas treating, gathering, processing, fractionation and transmission process.



The midstream natural gas industry is the link between exploration and production of natural gas and the delivery of its components to end-use markets. The midstream industry is generally characterized by regional competition based on the proximity of gathering systems and processing plants to natural gas producing wells.

Natural gas gathering. The natural gas gathering process begins with the drilling of wells into gas bearing rock formations. Once a well has been completed, the well is connected to a gathering system. Gathering systems typically consist of a network of small diameter pipelines and, if necessary, compression systems that collect natural gas from points near producing wells and transport it to larger pipelines for further transmission.

Natural gas treating. Natural gas has a varied composition depending on the field, the formation and the reservoir from which it is produced. Natural gas from certain formations in the Texas Gulf Coast is high in carbon dioxide. Treating plants are placed at or near a well and remove carbon dioxide and hydrogen sulfide from natural gas before it is introduced into gathering systems to ensure that it meets pipeline quality specifications.

Natural gas processing and fractionation. The principal components of natural gas are methane and ethane, but most natural gas also contains varying amounts of NGLs and contaminants, such as water, sulfur compounds, nitrogen or helium. Most natural gas produced by a well is not suitable for long-haul pipeline transportation or commercial use and must be processed to remove the heavier hydrocarbon components and contaminants. Natural gas in commercial distribution systems is composed almost entirely of methane and ethane, with moisture and other contaminants removed to very low concentrations. Natural gas is processed not only to remove unwanted contaminants that would interfere with pipeline transportation or use of the natural gas, but also to separate from the gas those hydrocarbon liquids that have higher value as NGLs. The removal and separation of individual hydrocarbons by processing is possible because of differences in weight, boiling point, vapor pressure and other physical characteristics. Natural gas processing involves the separation of natural gas into pipeline quality natural gas and a mixed NGL stream, as well as the removal of contaminants. NGL fractionation facilities separate mixed NGL streams into discrete NGL products: ethane, propane, isobutane, normal butane and natural gasoline.

Natural gas transmission. Natural gas transmission pipelines receive natural gas from mainline transmission pipelines, plant tailgates, and gathering systems and deliver it to industrial end-users, utilities and to other pipelines. All of our transmission pipelines are intrastate systems.

Risk Management

As we purchase natural gas, we establish a margin by selling natural gas for physical delivery to third party users, using over-the-counter derivative instruments or by entering into a future delivery

obligation under futures contracts on the New York Mercantile Exchange. Through these transactions, we seek to maintain a position that is substantially balanced between purchases, on the one hand, and sales or future delivery obligations, on the other hand. Our policy is not to acquire and hold natural gas future contracts or derivative products for the purpose of speculating on price changes.

Competition

The business of providing natural gas gathering, transmission, treating, processing and marketing services is highly competitive. We face strong competition in acquiring new natural gas supplies. Our competitors in obtaining additional gas supplies and in treating new natural gas supplies include major integrated oil companies, major interstate and intrastate pipelines, and other natural gas gatherers that gather, process and market natural gas. Competition for natural gas supplies is primarily based on the reputation, efficiency and reliability of the gatherer and the pricing arrangements offered by the gatherer. The main difference between us and our competitors is that we offer most midstream services, while our competitors typically offer only a few select services. Many of our competitors have substantially greater capital resources and control substantially greater supplies of natural gas. Our major competitors in the Texas Gulf Coast area for natural gas supplies and markets include El Paso Field Services, Kinder Morgan Inc., Houston Pipeline Company and Duke Energy Field Services. Our major competitors in Mississippi for natural gas supplies and markets include Southern Natural Gas and Gulf South Pipeline Company.

Our gas treating operations face competition from manufacturers of new treating plants and from a small number of regional operators that provide plant and operations similar to ours. We also face competition from vendors of used equipment that occasionally operate plants for producers. Our primary competitor for natural gas treating services in our principal market area is The Hanover Company.

In marketing natural gas, we have numerous competitors, including marketing affiliates of interstate pipelines, major integrated oil companies, and local and national natural gas gatherers, brokers and marketers of widely varying sizes, financial resources and experience. Local utilities and distributors of natural gas are, in some cases, engaged directly, and through affiliates, in marketing activities that compete with our marketing operations.

Natural Gas Supply

Our end-user pipelines have connections with major interstate and intrastate pipelines, which we believe have ample supplies of natural gas in excess of the volumes required for these systems. In connection with the construction and acquisition of our gathering systems, we evaluated well and reservoir data furnished by producers to determine the availability of natural gas supply for the systems. Based on those evaluations, we believe that there should be adequate natural gas supply to recoup our investment with an adequate rate of return. We do not routinely obtain independent evaluations of reserves dedicated to our systems due to the cost of such evaluations. Accordingly, we do not have estimates of total reserves dedicated to our systems or the anticipated life of such producing reserves.

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 a material impact on our results of operations.

Regulation

Regulation by FERC of Interstate Natural Gas Pipelines. Under the Natural Gas Act ("NGA"), the Federal Energy Regulatory Commission ("FERC") generally regulates the transportation of natural gas in interstate commerce. We do not own any interstate natural gas pipelines, so the FERC does not directly regulate any of our facilities or operations. However, as discussed below, we do perform some interstate transmission service that is incidental to our intrastate business, and this interstate transmission is subject to FERC rate regulation. Also, FERC's regulation of interstate transportation by others indirectly influences certain aspects of our business and the market for our products. In recent years, FERC has pursued pro-competitive policies in its regulation of interstate natural gas pipelines. However, we cannot assure you that FERC will continue this approach as it considers matters such as pipelines' rates and rules and policies that may affect rights of access to natural gas transportation capacity.

Intrastate Pipeline Regulation. Our intrastate natural gas pipeline operations are not subject to regulation by FERC, but they are subject to regulation by various agencies of the states in which they are located, principally the Texas Railroad Commission, or TRRC. However, to the extent that our intrastate pipeline systems provide incidental transportation of natural gas in interstate commerce, the rates, terms and conditions of such transportation services are subject to FERC jurisdiction under Section 311 of the Natural Gas Policy Act ("NGPA"). Section 311 applies to, among other things, the providing of transportation services by an intrastate natural gas pipeline on behalf of a local distribution company or an interstate natural gas pipeline. Most states have agencies that possess the authority to review and authorize natural gas transportation transactions and the construction, acquisition, abandonment and interconnection of physical facilities. Some states also have state agencies that regulate transportation rates, service terms and conditions and contract pricing to ensure their reasonableness and to ensure that the intrastate pipeline companies that they regulate do not discriminate among similarly situated customers.

Our operations in Texas are subject to the Texas Gas Utility Regulatory Act, as implemented by the TRRC. Generally the TRRC is vested with authority to ensure that rates charged for natural gas sales or transportation services are just and reasonable. The rates we charge for transportation services are deemed just and reasonable under Texas law unless challenged in a complaint. We cannot predict whether such a complaint will be filed against us or whether the TRRC will change its regulation of these rates.

A twelve-mile section of our Mississippi gathering system is regulated by the Mississippi Oil and Gas Board as it transports gas not owned by us for a fee. Our one hundred twenty-five mile gathering system in Oklahoma is not regulated by the Oklahoma Corporation Commission. Similarly, gathering systems we own in Alabama and Louisiana are not subject to regulation by the Alabama State Oil and Gas Board and the Louisiana Office of Conservation respectively. While it is possible that Alabama, Louisiana, Oklahoma, Mississippi and New Mexico may try to assert or expand jurisdiction on those lines, it is not likely that the assertion or expansion of that jurisdiction would have a significant effect on our operations in those states because all tend to apply Federal regulations to natural gas pipeline facilities without numerous additional state-specific requirements.

Gathering Pipeline Regulation. Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of FERC under the NGA. We own a number of natural gas pipelines that we believe meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to FERC jurisdiction. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of substantial, on-going litigation, so the classification and regulation of our gathering facilities, for purposes of rate regulation to the extent we

provide NGPA Section 311 services over such facilities, are subject to change based on future determinations by FERC and the courts. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements, and in some instances complaint-based rate regulation.

We are subject to state ratable take and common purchaser statutes. The ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply. These statutes have the effect of restricting our right as an owner of gathering facilities to decide with whom we contract to purchase or transport natural gas.

Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels since FERC has less extensively regulated the gathering activities of interstate pipeline transmission companies and a number of such companies have transferred gathering facilities to unregulated affiliates. For example, the TRRC has approved changes to its regulations governing transportation and gathering services performed by intrastate pipelines and gatherers, which prohibit such entities from unduly discriminating in favor of their affiliates. Our gathering operations could be adversely affected should they be subject in the future to the application of state or federal regulation of rates and services. Our gathering operations also may be or become subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Sales of Natural Gas. The price at which we sell natural gas currently is not subject to federal regulation and, for the most part, is not subject to state regulation. Our sales of natural gas are affected by the availability, terms and cost of pipeline transportation. As noted above, the price and terms of access to pipeline transportation are subject to extensive federal and state regulation. FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transmission companies, that remain subject to FERC's jurisdiction. These initiatives also may affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry and these initiatives generally reflect less extensive regulation. We cannot predict the ultimate impact of these regulatory changes on our natural gas marketing operations, and we note that some of FERC's more recent proposals may adversely affect the availability and reliability of interruptible transportation service on interstate pipelines. We do not believe that we will be affected by any such FERC action materially differently than other natural gas marketers with whom we compete.

Environmental Matters

General. Our operation and our possible future operation of processing and fractionation plants, pipelines and associated facilities in connection with the gathering and processing of natural gas and the transportation, fractionation and storage of NGLs is subject to stringent and complex federal, state and local laws and regulations relating to release of hazardous substances or wastes into the environment or otherwise relating to protection of the environment. As with the industry generally, compliance with existing and anticipated environmental laws and regulations increases our overall costs of doing business, including cost of planning, constructing, and operating plants, pipelines, and other facilities. Included in our construction and operation costs are capital cost items necessary to maintain or upgrade equipment and facilities. We will likely incur similar costs upon our acquisition of assets if we acquire operating assets.

Any failure to comply with applicable environmental laws and regulations, including those relating to obtaining required governmental approvals, may result in the assessment of administrative, civil, or criminal penalties, imposition of investigatory or remedial activities and, in less common circumstances, issuance of injunctions or construction bans or delays. While we believe that we currently hold material governmental approvals required to operate our major facilities, we are currently evaluating and updating permits for certain of our facilities that primarily were obtained in recent acquisitions. As part of the regular overall evaluation of our operations, we have implemented procedures to and are presently working to ensure that all governmental approvals, for both recently acquired facilities and existing operations are updated, as may be necessary. We believe that our operations and facilities are in substantial compliance with applicable environmental laws and regulations and that the cost of compliance with such laws and regulations will not have a material adverse effect on our operating results or financial condition.

The clear trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. Moreover, risks of process upsets, accidental releases or spills are associated with our possible future operations, and we cannot assure you that we will not incur significant costs and liabilities including those relating to claims for damage to property and persons as a result of such upsets, releases, or spills. In the event of future increases in costs, we may be unable to pass on those cost increases to our customers. A discharge of hazardous substances or wastes into the environment could, to the extent the event is not insured, subject us to substantial expense, including both the cost to comply with applicable laws and regulations and the cost related to claims made by neighboring landowners and other third parties for personal injury or damage to property. We will attempt to anticipate future regulatory requirements that might be imposed and plan accordingly in order to remain in compliance with changing environmental laws and regulations and in order to minimize the costs of such compliance.

Hazardous Substance and Waste. To a large extent, the environmental laws and regulations affecting our possible future operations relate to the release of hazardous substances or solid wastes into soils, groundwater, and surface water, and include measures to control environmental pollution of the environment. These laws and regulations generally regulate the generation, storage, treatment, transportation, and disposal of solid and hazardous wastes, and may require investigatory and corrective actions at facilities where such waste may have been released or disposed. For instance, the Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, also known as the "Superfund" law, and comparable state laws, impose liability without regard to fault or the legality of the original conduct, on certain classes of persons that contributed to a release of "hazardous substance" into the environment. These persons include the owner or operator of the site where a release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some cases, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other wastes released into the environment. Although "petroleum" as well as natural gas and NGLs are excluded from CERCLA's definition of a "hazardous substance," in the course of future, ordinary operations, we may generate wastes that may fall within the definition of a "hazardous substance." We may be responsible under CERCLA for all or part of the costs required to clean up sites at which such wastes have been disposed. We have not received any notification that we may be potentially responsible for cleanup costs under CERCLA or any analogous state laws.

We also generate, and may in the future generate, both hazardous and nonhazardous solid wastes that are subject to requirements of the federal Resource Conservation and Recovery Act, or RCRA, and comparable state statutes. From time to time, the Environmental Protection Agency, or EPA, has considered the adoption of stricter disposal standards for nonhazardous wastes, including crude oil and natural gas wastes. We are not currently required to comply with a substantial portion of the RCRA requirements because our operations generate minimal quantities of hazardous wastes. However, it is possible that some wastes generated by us that are currently classified as nonhazardous may in the future be designated as "hazardous wastes," resulting in the wastes being subject to more rigorous and costly disposal requirements. Changes in applicable regulations may result in an increase in our capital expenditures or plant operating expenses.

We currently own or lease, and have in the past owned or leased, and in the future we may own or lease, properties that have been used over the years for natural gas gathering and processing and for NGL fractionation, transportation and storage. Solid waste disposal practices within the NGL industry and other oil and natural gas related industries have improved over the years with the passage and implementation of various environmental laws and regulations. Nevertheless, some hydrocarbons and other solid wastes have been disposed of on or under various properties owned or leased by us during the operating history of those facilities. In addition, a number of these properties may have been operated by third parties over whom we had no control as to such entities' handling of hydrocarbons or other wastes and the manner in which such substances may have been disposed of or released. These properties and wastes disposed thereon may be subject to CERCLA, RCRA, and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes or property contamination, including groundwater contamination or to perform remedial operations to prevent future contamination.

We recently acquired two assets from DEFS 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 our purchase agreement, Duke 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, we do not expect to incur any material environmental liability associated with the Conroe or Cadeville sites.

Air Emissions. Our operations are, and our possible future operations will likely be, subject to the Clean Air Act and comparable state statutes. Amendments to the Clean Air Act were enacted in 1990. Moreover, recent or soon to be adopted changes to state implementation plans for controlling air emissions in regional, non-attainment areas require or will require most industrial operations in the United States to incur capital expenditures in order to meet air emission control standards developed by the EPA and state environmental agencies. As a result of these amendments, our processing and fractionating plants, pipelines, and storage facilities or any of our future assets that emit volatile organic compounds or nitrogen oxides may become subject to increasingly stringent regulations, including requirements that some sources install maximum or reasonably available control technology. Such requirements, if applicable to our operations, could cause us to incur capital expenditures in the next several years for air pollution control equipment in connection with maintaining or obtaining governmental approvals addressing air emission related issues. In addition, the 1990 Clean Air Act Amendments established a new operating permit for major sources, which applies to some of the our facilities and which may apply to some of our possible future facilities. Failure to comply with applicable air statutes or regulations may lead to the assessment of administrative, civil or criminal penalties, and may result in the limitation or cessation of construction or operation of certain air

emission sources. Although we can give no assurances, we believe implementation of the 1990 Clean Air Act Amendments will not have a material adverse effect on our financial condition or operating results.

Clean Water Act. The Federal Water Pollution Control Act, also known as the Clean Water Act, and similar state laws impose restrictions and strict controls regarding the discharge of pollutants, including natural gas liquid related wastes, into state waters or waters of the United States. Regulations promulgated pursuant to these laws require that entities that discharge into federal and state waters obtain National Pollutant Discharge Elimination System, or NPDES, and/or state permits authorizing these discharges. The Clean Water Act and analogous state laws assess administrative, civil and criminal penalties for discharges of unauthorized pollutants into the water and impose substantial liability for the costs of removing spills from such waters. In addition, the Clean Water Act and analogous state laws require that individual permits or coverage under general permits be obtained by covered facilities for discharges of storm water runoff. We believe that we are in substantial compliance with Clean Water Act permitting requirements as well as the conditions imposed thereunder, and that continued compliance with such existing permit conditions will not have a material effect on our results of operations.

Employee Safety. We are subject to the requirements of the Occupational Safety and Health Act, referred to as OSHA, and comparable state laws that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with the OSHA requirements, including general industry standards, record keeping requirements, and monitoring of occupational exposure to regulated substances.

Endangered Species Act. The Endangered Species Act restricts activities that may affect endangered species or their habitats. Presently, we operate in only one area that is designated as a critical habitat for a certain species of beetle. This area consists of 29 counties in eastern and central Oklahoma into which part of our gathering system extends. A coalition of oil and gas industry and regulatory agencies are currently working together to minimize impacts on future construction and operation activities for oil and gas production and transportation. This designated area has had no material effect on our operations in Oklahoma to date. While we have no reason to believe that we operate in any other area that is currently designed as habitat for endangered or threatened species, the discovery of previously unidentified endangered species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

Safety Regulations. Our pipelines are subject to regulation by the U.S. Department of Transportation under the Hazardous Liquid Pipeline Safety Act, as amended, or HLPSA, and the Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines) amendment to 49 CFR Part 192, effective February 14, 2004 relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. The HLPSA covers crude oil, carbon dioxide, NGL and petroleum products pipelines and requires any entity which owns or operates pipeline facilities to comply with the regulations under the HLPSA, to permit access to and allow copying of records and to make certain reports and provide information as required by the Secretary of Transportation. The Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines) amendment to 49 CFR Part 192 (PIM) requires operators of gas transmission pipelines and segments of gathering lines in certain populated areas to ensure the integrity of their pipelines through hydrostatic pressure testing, the use of in-line inspection tools or through risk-based direct assessment techniques. We believe that our pipeline operations are in substantial compliance with applicable HLPSA and PIM requirements; however, due to the possibility of new or amended laws and regulations or reinterpretation of existing laws and regulations, there can be no assurance that future

compliance with the HLPSA or PIM requirements will not have a material adverse effect on our results of operations or financial positions.

Office Facilities

In addition to our gathering and treating facilities discussed above, we occupy approximately 21,000 square feet, increasing up to approximately 40,000 square feet over the next two years, of space at our executive offices in Dallas, Texas under a lease expiring in March 2010.

Employees

As of December 31, 2003, our operating partnership, Crosstex Energy Services, L.P., had approximately 189 full-time employees. Approximately half of our employees were general and administrative, engineering, accounting and commercial personnel and the remainder were operational employees. We are not party to any collective bargaining agreements, and we have not had any significant labor disputes in the past. We believe that we have good relations with our employees.

Item 2. *Properties*

A description of our properties is contained in "Item 1. Business."

Title to Properties

Substantially all of our pipelines are constructed on rights-of-way granted by the apparent record owners of the property. Lands over which pipeline rights-of-way have been obtained may be subject to prior liens that have not been subordinated to the right-of-way grants. We have obtained, where necessary, easement agreements from public authorities and railroad companies to cross over or under, or to lay facilities in or along, watercourses, county roads, municipal streets, railroad properties and state highways, as applicable. In some cases, property on which our pipeline was built was purchased in fee. Our Gregory processing plant is on land that it owns in fee.

We believe that we have satisfactory title to all of our assets. Title to property may be subject to encumbrances. We believe that none of such encumbrances should materially detract from the value of our properties or from our interest in these properties or should materially interfere with their use in the operation of our business.

Item 3. *Legal Proceedings*

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

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

No matters were submitted to security holders during the fourth quarter of the year ended December 31, 2003.

PART II

Item 5. *Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities*

The Partnership's common units representing limited partner interests in the Partnership are listed on the NASDAQ National Market under the symbol "XTEX". Common units began trading on December 12, 2002, at an initial public offering price of $20.00 per common unit. On March 3, 2004, the market price for the common units was $51.85 per unit and there were approximately 5,195 record holders and beneficial owners (held in street name) of the Partnership's common units and one record holder of the Partnership's subordinated units. There is no established public trading market for the Partnership's subordinated units.

The following table shows the high and low closing sales prices per common unit, as reported by the NASDAQ National Market, for the periods indicated:

	Common Unit Price Range		Cash Distribution Paid Per Unit
	High	Low	
2003:			
Quarter Ended December 31,	$ 43.58	$ 38.55	$ 0.75(a)
Quarter Ended September 30,	39.80	33.25	0.70
Quarter Ended June 30,	34.40	24.36	0.55
Quarter Ended March 31,	24.50	21.48	0.576(b)
2002:			
Quarter ended December 31,	$ 21.75	$ 19.46	$ 0.00

(a) The distribution for the quarter ended December 31, 2003 and was paid on Febrruary 13, 2004.

(b) Reflects minimum quarterly distribution of $0.50 for the quarter ended March 31, 2003 and the pro rata portion of the $0.50 minimum quarterly distribution, covering the period for December 17, 2002 closing of the initial public offering through December 31, 2002.

Within 45 days after the end of each quarter, we will distribute all of our available cash, as defined in our partnership agreement, to unitholders of record on the applicable record date. During the subordination period (as described below), the common units will have the right to receive distributions of available cash from operating surplus in an amount equal to the minimum quarterly distribution of $0.50 per quarter, plus any arrearages in the payment of the minimum quarterly distribution on the common units from prior quarters, before any distributions of available cash from operating surplus may be made on the subordinated units. Our available cash consists generally of all cash on hand at the end of the fiscal quarter, less reserves that our general partner determines are necessary to:

- provide for the proper conduct of our business;
- comply with applicable law, any of our debt instruments, or other agreements; or
- provide funds for distributions to our unitholders and to our general partner for any one or more of the next four quarters;

plus all cash on hand for the quarter resulting from working capital borrowings made after the end of the quarter on the date of determination of available cash.

Our general partner has broad discretion to establish cash reserves that it determines are necessary or appropriate to properly conduct our business. These can include cash reserves for future capital and maintenance expenditures, reserves to stabilize distributions of cash to the unitholders and our general partner, reserves to reduce debt, or, as necessary, reserves to comply with the terms of any of our agreements or obligations. Our distributions are effectively made 98 percent to unitholders and two percent to our general partner, subject to the payment of incentive distributions to our general partner if certain target cash distribution levels to common unitholders are achieved. Incentive distributions to our general partner increase to 15 percent, 25 percent and 50 percent based on incremental distribution thresholds as set forth in our partnership agreement.

Our ability to distribute available cash is contractually restricted by the terms of our credit facility. Our credit facility contains covenants requiring us to maintain certain financial ratios. We are prohibited from making any distributions to unitholders if the distribution would cause an event of default, or an event of default is existing, under our credit facility. Please read "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Description of Indebtedness."

During the subordination period, the common units will have the right to receive distributions of available cash from operating surplus in an amount equal to the minimum quarterly distribution of $0.50 per quarter, plus any arrearages in the payment of the minimum quarterly distribution on the common units from prior quarters, before any distributions of available cash from operating surplus may be made on the subordinated units. The purpose of the subordinated units is to increase the likelihood that during the subordination period there will be available cash to be distributed on the common units.

The subordination period will extend until the first day of any quarter beginning after December 31, 2007 in which each of the following tests are met:

- distributions of available cash from operating surplus on each of the outstanding common units and subordinated units equaled or exceeded the minimum quarterly distribution for each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date;
- the "adjusted operating surplus" as defined in the partnership agreement generated during each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date equaled or exceeded the sum of the minimum quarterly distributions on all of the outstanding common units and subordinated units during those periods on a fully diluted basis and the related distribution on the 2% general partner interest during those periods; and
- there are no arrearages in payment of the minimum quarterly distribution on the common units.

Upon expiration of the subordination period, each outstanding subordinated unit will convert into one common unit and will participate pro rata with the other common units in distributions of available cash.

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.(1)	
	Year Ended December 31, 2003	Year Ended December 31, 2002	Year Ended December 31, 2001	Eight Months Ended December 31, 2000	Four Months Ended April 30, 2000	Year Ended December 31, 1999
Statement of Operations Data:						
Revenues:						
Midstream	$ 993,140	$ 437,676	$ 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	452,493	387,026	105,400	9,538	17,666
Operating costs and expenses:						
Midstream purchased gas	946,412	413,982	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(2)	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)	(2,703)	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	447,929	388,865	103,362	17,517	16,388
Operating income (loss)	18,439	4,564	(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	155	174	115	381	(138)
Total other income (expense)	(3,213)	(2,562)	(2,079)	(415)	302	(776)
Net income (loss)	$ 15,226	$ 2,002	($ 3,918)	$ 1,623	($ 7,677)	$ 502
Net income (loss) per limited partner unit—basic(3)	$ 1.78	$ 0.04	N/A	N/A	N/A	N/A
Net income (loss) per limited partner unit—diluted(3)	$ 1.75	$ 0.04	N/A	N/A	N/A	N/A
Distributions per limited partner unit(4)	$ 2.50	$ 0.056	N/A	N/A	N/A	N/A
Balance Sheet Data:						
Working capital surplus (deficit)	$ (2,914)	$ (8,672)	$ (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	365,303	232,438	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	156,268	89,816	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	$ 23,694	$ 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(5)	$ 59,683	$ 32,744	$ 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)(6)	90,000	98,000	63,000	36,000	27,000	13,000

(1) 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.

(2) 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.

(3) 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.

(4) 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.

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

(6) 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.

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.

	Year ended December 31, 2003			
	Gas Purchased		Gas Sold	
Asset or Business	Fixed Amount to Index	Percentage of Index	Fixed Amount to Index	Percentage of Index
	(in billions of MMBtus)			
Gulf Coast system	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% 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	2001
		(in millions)	
Midstream revenues	$ 993.1	$ 437.7	$ 362.7
Midstream purchased gas	946.4	414.0	344.8
Midstream gross margin	46.7	23.7	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	$ 32.7	$ 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 $23.7 million for the year ended December 31, 2002, an increase of $23.0 million, or 97%. 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 volume 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 $2.7 million for the year ended December 31, 2002, a decrease of $0.8 million, or 30%. 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 gains of $0.9 million 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 $2.0 million for the year ended December 31, 2002, an increase of $13.2 million. This was generally the result of the increase in gross margin of $26.9 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 $23.7 million for the year ended December 31, 2002 compared to $17.9 million for the year ended December 31, 2001, an increase of $5.8 million, or 32%. 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 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 $2.7 million 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 $6.4 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. In addition, gains of $0.9 million relating primarily to options bought and/or sold in the management of the company's Enron position were booked in 2002. Offsetting the gains from the producer services off-system gas marketing operations in 2001 was the $5.7 million reserve booked 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 December31, 2001, an increase of $.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 $2.0 million compared to ($3.9) million for the year ended December 31, 2001, an increase of $5.9 million. Gross margin increased by $8.6 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 $14.0 million in 2002. Changes in working capital provided $12.8 million in cash flows from operating activities in 2003 and used $19.7 million 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 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:

Contractual Obligations	Payments due by period 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 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 7A. *Quantitative and Qualitative Disclosures about Market Risk*

Market risk is the risk of loss arising from adverse changes in market rates and prices. We face market risk from commodity price variations, primarily due to fluctuations in the price of a portion of the natural gas we sell; and for the portion of the natural gas we process and for which we have taken the processing risk, we are at risk for the difference in the value of the NGL products we produce versus the value of the gas used in fuel and shrinkage in their production. We also incur credit risks and risks related to interest rate variations.

Commodity Price Risk. Approximately 8.4% of the natural gas we market is purchased at a percentage of the relevant natural gas index price, as opposed to a fixed discount to that price. As a result of purchasing the gas at a percentage of the index price, our resell margins are higher during periods of higher natural gas prices and lower during periods of lower natural gas prices. In addition, of the gas we process at our Gregory Processing Plant, we were exposed to the processing risk on 16% of the gas we purchased during the year ended December 31, 2003. Our processing margins on this portion of the gas will be higher during periods when the price of gas is low relative to the value of the liquids produced and our margins will be lower during periods when the value of gas is high relative to the value of liquids. For the year ended December 31, 2003, a $0.01 per gallon change in NGL prices

offset by a change of $0.10 per MMBtu in the price of natural gas would have changed our processing margin by $170,000. Changes in natural gas prices indirectly may impact our profitability since prices can influence drilling activity and well operations and thus the volume of gas we can gather, transport, process and treat.

Our primary commodity risk management objective is to reduce volatility in our cash flows. We maintain a Risk Management Committee, including members of senior management, which oversees all hedging activity. We enter into hedges for natural gas using NYMEX futures or over-the-counter derivative financial instruments with only certain well-capitalized counterparties which have been approved by our Risk Management Committee. Hedges to protect our processing margins are generally for a more limited time frame than is possible for hedges in natural gas, as the financial markets for NGLs are not as developed as the markets for natural gas. Such hedges generally involve taking a short position with regard to the relevant liquids and an offsetting short position in the required volume of natural gas.

The use of financial instruments may expose us to the risk of financial loss in certain circumstances, including instances when (1) sales volumes are less than expected requiring market purchases to meet commitments, or (2) our counterparties fail to purchase the contracted quantities of natural gas or otherwise fail to perform, as happened in the case of the Enron loss discussed above. To the extent that we engage in hedging activities we may be prevented from realizing the benefits of favorable price changes in the physical market. However, we are similarly insulated against decreases in such prices.

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

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

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. Our 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. Changes in the fair value of our 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 we are exposed to counterparty risk, we analyze the counterparty's financial condition prior to entering into an agreement, establishes limits, and monitors the appropriateness of these limits on an ongoing basis.

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

Interest Rate Risk. We are exposed to changes in interest rates, primarily as a result of our long-term debt with floating interest rates. At December 31, 2003, we had $20.0 million of indebtedness outstanding under floating rate debt. We have interest rate swap agreements to adjust the ratio of fixed and floating rates in the debt portfolio, wherein we have swapped floating rates for fixed rates of 2.29% and the applicable margin through November 1, 2004. The impact of a 100 basis point increase in interest rates on our debt level as of December 31, 2003 would result in an increase in interest expense and a decrease in income before taxes of approximately $41,000 per year. This amount has been determined by considering the impact of such hypothetical interest rate increase on our non-hedged, floating rate debt outstanding at December 31, 2003.

Item 8. *Financial Statements and Supplementary Data*

The Report of Independent Public Accountants, Consolidated Financial Statements and supplementary financial data required by this Item are set forth on pages F-1 through F-35 and S-1 of this Report and are incorporated herein by reference.

Item 9. *Changes in and Disagreements With Accountants on Accounting and Financial Disclosure*

None.

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 our disclosure controls and procedures were 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.

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

PART III

Item 10. *Directors and Executive Officers of the Registrant*

As is the case with many publicly traded partnerships, we do not have officers, directors or employees. Our operations and activities are managed by the general partner of our general partner, Crosstex Energy GP, LLC. Our operational personnel are employees of the operating partnership. References to our general partner, unless the context otherwise requires, includes Crosstex Energy GP, LLC. References to our officers, directors and employees are references to the officers, directors and employees of Crosstex Energy GP, LLC. or the operating partnership.

Unit-holders do not directly or indirectly participate in our management or operation. Our general partner owes a fiduciary duty to the unit-holders, as limited by our partnership agreement. As a general partner, our general partner is liable for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made specifically non-recourse to it. Whenever possible, our general partner intends to incur indebtedness or other obligations on a non-recourse basis.

The following table shows information for the directors and executive officers of Crosstex Energy GP, LLC. Executive officers and directors are elected annually and have held the following positions since the date of the closing of our initial public offering, except for Messrs. Davis and Lawrence who have held the following positions with the Crosstex Energy GP, LLC since its formation in July 2002, and Mr. Burke, who became a director in August 2003.

Name	Age	Position with Crosstex Energy GP, LLC
Barry E. Davis	42	President, Chief Executive Officer and Director
James R. Wales	50	Executive Vice President—Southern Division
A. Chris Aulds	42	Executive Vice President—Northern and Treating Divisions
Jack M. Lafield	53	Executive Vice President—Business Development
William W. Davis	50	Executive Vice President and Chief Financial Officer
Michael P. Scott	49	Senior Vice President—Technical Services
Frank M. Burke	64	Director
C. Roland Haden	63	Director
Bryan H. Lawrence	61	Chairman of the Board
Sheldon B. Lubar	74	Director
Robert F. Murchison	49	Director
Stephen A. Wells	60	Director

Barry E. Davis, President, Chief Executive Officer and Director, led the management buyout of the midstream assets of Comstock Natural Gas, Inc. in December 1996, which transaction resulted in the formation of our predecessor. Mr. Davis was President and Chief Operating Officer of Comstock Natural Gas and founder of Ventana Natural Gas, a gas marketing and pipeline company that was purchased by Comstock Natural Gas. Mr. Davis started Ventana Natural Gas in June 1992. Prior to starting Ventana, he was Vice President of Marketing and Project Development for Endevco, Inc. Before joining Endevco, Mr. Davis was employed by Enserch Exploration in the marketing group. Mr. Davis holds a B.B.A. in Finance from Texas Christian University.

James R. Wales, Executive Vice President—Southern Division, joined our predecessor in December 1996. As one of the founders of Sunrise Energy Services, Inc., he helped build Sunrise into a major national independent natural gas marketing company, with sales and service volumes in excess of 600,000 MMBtu/d. Mr. Wales started his career as an engineer with Union Carbide. In 1981, he joined Producers Gas Company, a subsidiary of Lear Petroleum Corp., and served as manager of its Mid-Continent office. In 1986, he joined Sunrise as Executive Vice President of Supply, Marketing and Transportation. From 1993 to 1994, Mr. Wales was the Chief Operating Officer of Triumph Natural

Gas, Inc., a private midstream business. Prior to joining Crosstex, Mr. Wales was Vice President for Teco Gas Marketing Company. Mr. Wales holds a B.S. degree in Civil Engineering from the University of Michigan, and a Law degree from South Texas College of Law.

A. Chris Aulds, Executive Vice President—Northern and Treating Divisions together with Barry E. Davis, participated in the management buyout of Comstock Natural Gas in December 1996. Mr. Aulds joined Comstock Natural Gas, Inc. in October 1994 as a result of the acquisition by Comstock of the assets and operations of Victoria Gas Corporation. Mr. Aulds joined Victoria in 1990 as Vice President responsible for gas supply, marketing and new business development and was directly involved in the providing of risk management services to gas producers. Prior to joining Victoria, Mr. Aulds was employed by Mobil Oil Corporation as a production engineer before being transferred to Mobil's gas marketing division in 1989. There he assisted in the creation and implementation of Mobil's third-party gas supply business segment. Mr. Aulds holds a B.S. degree in Petroleum Engineering from Texas Tech University.

Jack M. Lafield, Executive Vice President—Corporate Development, joined our predecessor in August 2000. For five years prior to joining Crosstex, Mr. Lafield was Managing Director of Avia Energy, an energy consulting group, and was involved in all phases of acquiring, building, owning and operating midstream assets and natural gas reserves. He also provided project development and consulting in domestic and international energy projects to major industry and financing organizations, including development, engineering, financing, implementation and operations. Prior to consulting, Mr. Lafield held positions of President and Chief Executive Officer of Triumph Natural Gas, a private midstream business he founded, President and Chief Operating Officer of Nagasco, Inc. (a joint venture with Apache Corporation), President of Producers' Gas Company, and Senior Vice President of Lear Petroleum Corp. Mr. Lafield holds a B.S. degree in Chemical Engineering from Texas A&M University, and is a graduate of the Executive Program at Stanford University.

William W. Davis, Executive Vice President and Chief Financial Officer, joined our predecessor in September 2001, and has 25 years of finance and accounting experience. Prior to joining our predecessor, Mr. Davis held various positions with Sunshine Mining and Refining Company from 1983 to September 2001, including Vice President—Financial Analysis from 1983 to 1986, Senior Vice President and Chief Accounting Officer from 1986 to 1991 and Executive Vice President and Chief Financial Officer from 1991 to 2001. In addition, Mr. Davis served as Chief Operating Officer in 2000 and 2001. Mr. Davis graduated magna cum laude from Texas A&M University with a B.B.A. in Accounting and is a Certified Public Accountant. Mr. Davis is not related to Barry E. Davis.

Michael P. Scott, Senior Vice President—Technical Services, joined our predecessor in July 2001. Before joining our predecessor, Mr. Scott held various positions at Aquila Gas Pipeline Corporation, including Director of Engineering from 1992 to 2001, Director of Operations from 1990 to 1992, and Director of Project Development from 1989 to 1990. Prior to Aquila, Mr. Scott held various project development and engineering positions at Cabot Corporation/Cabot Transmission, Perry Gas Processors and General Electric. Mr. Scott holds a B.S. degree in Mechanical Engineering from Oklahoma State University.

Frank M. Burke joined Crosstex Energy GP, LLC as a director in August 2003. Mr. Burke has served as Chairman, Chief Executive Officer and Managing General Partner of Burke, Mayborn Company Ltd., a private investment company located in Dallas, Texas, since 1984. Prior to that, Mr. Burke was a partner in Peat, Marwick, Mitchell & Co. (now KPMG). He is a member of the National Petroleum Council and also serves as a director of Arch Coal, Inc., Dorchester Minerals, L.P., Kaneb Pipe Line Partners, L.P., Xanser Corporation and Kaneb Services LLC. Mr. Burke received his Bachelor of Business Administration and Master of Business Administration from Texas Tech University and his Juris Doctor from Southern Methodist University. He is a Certified Public Accountant and member of the State Bar of Texas.

C. Roland Haden joined us as a director upon the completion of our initial public offering. Mr. Haden held the positions of Vice Chancellor of the Texas A&M System, Director of the Texas Engineering Experiment Station and Dean of Look College of Engineering at Texas A&M University from 1993 to 2002. Prior to joining Texas A&M University, Mr. Haden served as Vice Chancellor for Academic Affairs and Provost of Louisiana State University from 1991 to 1993 and held various positions with Arizona State University, including Dean and Professor of Engineering & Applied Sciences from 1989 to 1991, Provost, ASU West Campus from 1988 to 1989, Vice President for Academic Affairs from 1987 to 1988 and Dean and Professor of Engineering and Applied Sciences from 1978 to 1987. Mr. Haden formerly served as a director of Square D Company, a Fortune 500 electrical manufacturing company, as a director of E-Systems, a Fortune 500 defense contractor, and as a member of the Telecommunications Advisory Board of A.T. Kearney, a nationally ranked consulting firm. He has been a director of Inter-tel, Inc., a leading telecommunications company, since 1983. Mr. Haden holds a bachelor's degree from the University of Texas, Arlington, a Masters degree from the California Institute of Technology, and a Ph.D. from the University of Texas, Austin, all in electrical engineering.

Bryan H. Lawrence, Chairman of the Board, joined our predecessor as a director in May 2000. Mr. Lawrence is a founder and senior manager of Yorktown Partners LLC, the manager of the Yorktown group of investment partnerships, which make investments in companies engaged in the energy industry. The Yorktown partnerships were formerly affiliated with the investment firm of Dillon, Read & Co. Inc., where Mr. Lawrence had been employed since 1966, serving as a Managing Director until the merger of Dillon Read with SBC Warburg in September 1997. Mr. Lawrence also serves as a director of D&K Healthcare Resources, Inc., Hallador Petroleum Company, TransMontaigne Inc., and Vintage Petroleum, Inc. (each a United States publicly traded company) and Cavell Energy Corp. (a Canadian publicly traded company) and certain non-public companies in the energy industry in which Yorktown partnerships hold equity interests including PetroSantander Inc., Savoy Energy, L.P., Athanor B.V., Camden Resources, Inc., ESI Energy Services Inc., Ellora Energy Inc., Dernick Resources Inc., Cinco Natural Resources Corp., Peak Energy Resources, Inc., Approach Resources Inc., Nytis Exploration Co., and Compass Petroleum Ltd. Mr. Lawrence is a graduate of Hamilton College and also has an M.B.A. from Columbia University.

Sheldon B. Lubar joined us as a director upon the completion of our initial public offering. Mr. Lubar has been Chairman of the Board of Lubar & Co. Incorporated, a private investment and venture capital firm he founded, since 1977. He was Chairman of the Board of Christiana Companies, Inc., a logistics and manufacturing company, from 1987 until its merger with Weatherford International in 1995. Mr. Lubar has also been a Director of C2, Inc., a logistics and manufacturing company, since 1995, MGIC Investment Corporation, a mortgage insurance company, since 1991, Grant Prideco, Inc., an energy services company, since 2000, and Weatherford International, Inc., an energy services company, since 1995. Mr. Lubar holds a bachelor's degree in Business Administration and a Law degree from the University of Wisconsin—Madison. He was awarded an honorary Doctor of Commercial Science degree from the University of Wisconsin—Milwaukee.

Robert F. Murchison joined us as a director upon the completion of our initial public offering. Mr. Murchison has been the President of the general partner of Murchison Capital Partners, L.P., a private equity investment partnership since 1992. Prior to founding Murchison Capital Partners, L.P., Mr. Murchison held various positions with Romacorp, Inc., the franchisor and operator of Tony Roma's restaurants, including Chief Executive Officer from 1984 to 1986 and Chairman of the board of directors from 1984 to 1993. He served as a director of Cenergy Corporation, an oil and gas exploration and production company, from 1984 to 1987, Conquest Exploration Company from 1987 to 1991 and has served as a director of TNW Corporation, a short line railroad holding company, since 1981 and Tecon Corporation, a holding company with holdings in real estate development, investor

owned water utilities, rail car repair and the fund of funds management business, since 1978. Mr. Murchison holds a bachelor's degree in history from Yale University.

Stephen A. Wells joined us as a director upon the completion of our initial public offering. Mr. Wells has been the President of Wells Resources, Inc., a private oil, gas and ranching company since 1983. Mr. Wells has served in executive management positions with various energy companies, with an emphasis in oil field services. He served as Chief Executive Officer and director of Grasso Corporation, a contract production management company, from 1992 to 1994, Chief Executive Officer and director of Coastwide Energy Services, Inc. from 1993 to 1996, and President, Chief Executive Officer and director of Wells Strathclyde Company, an oil field services company he co-founded from 1978 to 1982. Mr. Wells also serves as a director and audit committee chair of Oil States International and as a director and audit committee chair of Pogo Producing Company. Mr. Wells holds a bachelor's degree in accounting from Abilene Christian University.

"Independent" Directors

Messrs. Burke, Haden, Lubar, Murchison and Wells qualify as "independent" in accordance with the published listing requirements of The NASDAQ Stock Market (NASDAQ). The NASDAQ independence definition includes a series of objective tests, such as that the director is not an employee of the company and has not engaged in various types of business dealings with the company. In addition, as further required by the NASDAQ rules, the board of directors has made a subjective determination as to each independent director that no relationships exist which, in the opinion of the board, would interfere with the exercise of independent judgment in carrying out the responsibilities of a director.

In addition, the members of the Audit Committee of the board of directors of our general partner also each qualify as "independent" under special standards established by the Securities and Exchange Commission (SEC) for members of audit committees, and the Audit Committee includes at least one member who is determined by the board of directors to meet the qualifications of an "audit committee financial expert" in accordance with SEC rules, including that the person meets the relevant definition of an "independent" director. Mr. Burke is the independent director who has been determined to be an audit committee financial expert. Unitholders should understand that this designation is a disclosure requirement of the SEC related to Mr. Burke's experience and understanding with respect to certain accounting and auditing matters. The designation does not impose on Mr. Burke any duties, obligations or liability that are greater than are generally imposed on him as a member of the Audit Committee and board of directors, and his designation as an audit committee financial expert pursuant to this SEC requirement does not affect the duties, obligations or liability of any other member of the Audit Committee or board of directors.

Board Committees

The board of directors of Crosstex Energy GP, LLC currently has, and appoints the members of, standing Audit, Compensation and Conflicts Committees. Each member of the Audit, Compensation and Conflicts Committees is an independent director in accordance with NASDAQ standards described above. Each of the board committees has a written charter approved by the board. Copies of the charters will be provided to any person, without charge, upon request. Contact Kathie Keller at 214-721-9327 to request a copy of a charter or send your request to Crosstex Energy, L.P., Attn: Kathie Keller, 2501 Cedar Springs, Suite 600, Dallas, Texas 75201.

The Audit Committee of Crosstex Energy GP, LLC, comprised of Messrs. Burke (chair), Wells and Haden, assists the board of directors in its general oversight of our financial reporting, internal controls and audit functions, and is directly responsible for the appointment, retention, compensation and oversight of the work of our independent auditors.

Two members of the board of directors of Crosstex Energy GP, LLC, namely Messrs. Haden (chair) and Wells, serve on a conflicts committee, which reviews specific matters that the board believes may involve conflicts of interest between our general partner and Crosstex Energy, L.P. The conflicts committee determines if the resolution of a conflict of interest is fair and reasonable to us. The members of the conflicts committee are not officers or employees of our general partner or directors, officers or employees of its affiliates. Any matters approved by the conflicts committee will be conclusively deemed to be fair and reasonable to us, approved by all of our partners, and not a breach by our general partner of any duties owed to us or our unit-holders.

The Compensation Committee of Crosstex Energy GP, LLC, comprised of Messrs. Lubar (chair) and Murchison, oversees compensation decisions for the officers of the General Partner as well as the compensation plans described herein

Code of Ethics

Crosstex Energy GP, LLC has adopted a Code of Business Conduct and Ethics applicable to all officers, and its independent directors, who are not employees of Crosstex Energy GP, LLC, with regard to Partnership-related activities. The Code of Business Conduct and Ethics incorporate guidelines designed to deter wrongdoing and to promote honest and ethical conduct and compliance with applicable laws and regulations. They also incorporate our expectations of our and Crosstex Energy GP, LLC's employees that enable us to provide accurate and timely disclosure in our filings with the Securities and Exchange Commission and other public communications. A copy of our Code of Business Conduct and Ethics will be provided to any person, without charge, upon request. Contact Kathie Keller at 214-721-9327 to request a copy of a charter or send your request to Crosstex Energy, L.P., Attn: Kathie Keller, 2501 Cedar Springs, Suite 600, Dallas, Texas 75201. If any substantive amendments are made to the Code of Business Conduct and Ethics or if we or Crosstex Energy GP, LLC grant any waiver, including any implicit waiver, from a provision of the code to any of Crosstex Energy GP, LLC's executive officers and directors, we will disclose the nature of such amendment or waiver in a report on Form 8-K.

Section 16(a)—Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires the directors and certain officers of the General Partner and any 10% beneficial owners of the Partnership to send reports of their beneficial ownership of Common Units and changes in beneficial ownership to the Securities and Exchange Commission. Based on our records, we believe that during fiscal 2003 all of such reporting persons complied with all Section 16(a) filing requirements applicable to them.

Reimbursement of Expenses of our General Partner and its Affiliates

Our general partner does not receive any management fee or other compensation in connection with its management of Crosstex Energy, L.P. However, our general partner performs services for us and is reimbursed by us for all expenses incurred on our behalf, including the costs of employee, officer and director compensation and benefits, as well as all other expenses necessary or appropriate to the conduct of our business. The partnership agreement provides that our general partner will determine the expenses that are allocable to us in any reasonable manner determined by our general partner in its sole discretion. For the twelve month period ending December 31, 2003, the amount which we reimbursed the 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 behalf of the partnership. See Item 13. "Certain Relationships and Related Transactions."

Item 11. *Executive Compensation*

The following table sets forth certain compensation information for our Chief Executive Officer and the five other most highly compensated executive officers in 2002 and 2003. We reimburse our general partner and its affiliates for expenses incurred on our behalf, including the costs of officer compensation allocable to us. The named executive officers have also received certain equity-based awards from our general partner's general partner. The Partnership was formed in July 2002 but conducted no business until mid-December 2002. As such, the compensation set forth below includes salary and bonus information paid to each of the named executive officers by the Partnership and its predecessor, prior to mid-December 2002.

Summary Compensation Table

		Annual Compensation(1)			Long Term Compensation Awards		
Name and Principal Position	Year	Salary(1) ($)	Bonus(2) ($)	Other Annual Compensation ($)	Restricted Unit Awards ($)	Units Underlying Options (#)(3)	All Other Compensation ($)
Barry E. Davis	2003	$ 201,500	$ 177,000	—	$ 285,670	—	—
President and Chief Executive Officer	2002	201,500	100,750	—	—	30,000	—
James R. Wales	2003	171,064	108,000	—	181,790	—	—
Executive Vice President—Southern Division	2002	171,064	59,872	—	—	20,000	—
A. Chris Aulds	2003	171,064	108,000	—	181,790	—	—
Executive Vice President-Northern and Treating Divisions	2002	171,064	59,872	—	—	20,000	—
Jack M. Lafield	2003	160,875	108,000	—	181,790	—	—
Executive Vice President—Business Development	2002	160,875	56,306	—	—	17,500	—
William W. Davis	2003	160,875	108,000	—	181,790	—	—
Executive Vice President and Chief Financial Officer	2002	160,875	93,306	—	—	17,500	—
Michael P. Scott	2003	134,304	90,000	—	103,880	—	—
Senior Vice President-Technical Services	2002	134,304	47,007	—	—	12,500	—

(1) Reflects the aggregate salary paid by the registrant and its predecessor for fiscal 2002 and 2003. The portion of the amount shown paid by the registrant subsequent to the closing of its initial public offering on December 17, 2002 for each of Messrs. Davis, Wales, Aulds, Lafield, W. Davis, and Scott was $8,396, $7,128, $7,128, $6,703, $6,703 and $5,596, respectively.

(2) Performance bonuses, for fiscal 2002 were earned by the executive officers for service to the registrant's predecessor prior to the closing of its initial public offering.

(3) Executive officers received equity-based awards from our general partner in 2002 and 2003. For a description of awards granted to date under the Long-Term Incentive Plan. See "—Long-Term Incentive Plan."

Employment Agreements

The executive officers of the general partner of our general partner, including Barry E. Davis, James R. Wales, A. Chris Aulds, Jack M. Lafield, William W. Davis and Michael P. Scott, have entered into employment agreements with Crosstex Energy, L.P. The following is a summary of the material provisions of those employment agreements. All of these employment agreements are substantially similar, with certain exceptions as set forth below.

Each of the employment agreements has an initial term that expires two years from the effective date, but will automatically be extended such that the remaining term of the agreements will not be less than one year. The employment agreements provide for a base annual salary of $218,400, $187,200,

$187,200, $176,00, $176,000 and $156,000 for Barry E. Davis, James R. Wales, A. Chris Aulds, Jack M. Lafield, William W. Davis and Michael P. Scott, respectively, for 2004.

Except in the event of our becoming bankrupt or ceasing operations, termination for cause or termination by the employee other than for good reason, the employment agreements provide for continued salary payments, bonus and benefits following termination of employment for the remainder of the employment term under the agreement. If a change in control occurs during the term of an employee's employment and either party to the agreement terminates the employee's employment as a result thereof, the employee will be entitled to receive salary payments, bonus and benefits following termination of employment for the remainder of the employment term under the agreement.

The employment agreements also provide for a noncompetition period that will continue until the later of one year after the termination of the employee's employment or the date on which the employee is no longer entitled to receive severance payments under the employment agreement. During the noncompetition period, the employees are generally prohibited from engaging in any business that competes with us or our affiliates in areas in which we conduct business as of the date of termination and from soliciting or inducing any of our employees to terminate their employment with us or accept employment with anyone else or interfere in a similar manner with our business.

Long-Term Incentive Plan

Crosstex Energy GP, LLC adopted a long-term incentive plan for employees and directors of Crosstex Energy GP, LLC and its affiliates who perform services for us.

The long-term incentive plan consists of two components: restricted units and unit options. The long-term incentive 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 Crosstex Energy GP, LLC's board of directors.

Crosstex Energy GP, LLC's board of directors in its discretion may terminate or amend the long-term incentive plan at any time with respect to any units for which a grant has not yet been made. Crosstex Energy GP, LLC's board of directors also has the right to alter or amend the long-term incentive plan or any part of the plan from time to time, including increasing the number of units that may be granted subject to unit-holder approval as required by the exchange upon which the common units are listed at that time. However, no change in any outstanding grant may be made that would materially impair the rights of the participant without the consent of the participant.

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 the future, the compensation committee may make grants under the plan to employees and directors containing such terms as the compensation committee shall determine under the plan. The committee may base its determination upon the achievement of specified financial objectives. In addition, the restricted units will vest upon a change of control of us, our general partner or Crosstex Energy GP, LLC.

If a grantee's employment terminates for any reason, other than death, disability or retirement, the grantee's restricted units will be automatically forfeited unless, and to the extent, the compensation committee provides otherwise. If a grantee is a director and his membership on the board of directors is terminated for cause, the grantee's restricted units will be automatically forfeited unless, and to the extent, the compensation committee provides otherwise. Common units to be delivered upon the vesting of restricted units may be common units acquired by Crosstex Energy GP, LLC in the open market, common units already owned by Crosstex Energy GP, LLC, common units acquired by Crosstex Energy GP, LLC directly from us or any other person or any combination of the foregoing. Crosstex

Energy GP, LLC will be entitled to reimbursement by us for the cost incurred in acquiring common units. If we issue new common units upon vesting of the restricted units, the total number of common units outstanding will increase. The compensation committee, in its discretion, may grant tandem distribution equivalent rights with respect to restricted units which entitles the grantee to distributions attributable to the restricted units prior to vesting of such units.

We intend the issuance of the common units upon vesting of the restricted units under the plan 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 we will receive no remuneration for the units.

Unit Options. The long-term incentive plan currently permits the grant of options covering common units. 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, the unit options will become exercisable upon a change in control of us, our general partner or Crosstex Energy GP, LLC or upon the achievement of specified financial objectives.

Upon exercise of a unit option, Crosstex Energy GP, LLC will acquire common units in the open market or directly from us or any other person or use common units already owned by Crosstex Energy GP, LLC, or any combination of the foregoing. Crosstex Energy GP, LLC will be entitled to reimbursement by us for the difference between the cost incurred by it in acquiring these common units and the proceeds received by it from an optionee at the time of exercise. Thus, the cost of the unit options will be borne by us. If we issue new common units upon exercise of the unit options, the total number of common units outstanding will increase, and Crosstex Energy GP, LLC will pay us the proceeds it received from the optionee upon exercise of the unit option. The unit option plan has been designed to furnish additional compensation to employees and directors and to align their economic interests with those of common unit-holders.

Option Grants

There were no unit options granted to the named executive officers in 2003.

Option Exercises and Year-End Option Values

The following table provides information about the number of units issued upon option exercises by the named executive officers during 2003, and the value realized by the named executive officers. The table also provides information about the number and value of options that were held by the named executive officers at December 31, 2003.

Aggregated Option Exercise in Last Fiscal Year and Fiscal Year End Option Values

Name	Shares Acquired on Exercise (#)	Value Realized ($)	Number of Securities Underlying Unexercised Options at 12/31/03 (#)		Value of Unexercised In-the-Money Options at 12/31/03 ($)	
			Exercisable	Unexercisable	Exercisable	Unexercisable
Barry E. Davis	—	—	10,000	20,000	$ 213,000	$ 426,000
James R. Wales	—	—	6,667	13,333	142,000	284,000
A. Chris Aulds	—	—	6,667	13,333	142,000	284,000
Jack M. Lafield	—	—	5,833	11,667	124,250	248,500
William W. Davis	—	—	5,833	11,667	124,250	248,500
Michael P. Scott	—	—	4,167	8,333	88,750	177,500

The closing price for the common units was $41.30.

Compensation of Directors

Each director of Crosstex Energy GP, LLC who is not an employee of Crosstex Energy GP, LLC (except Mr. Lawrence) is paid an annual retainer fee of $25,000. Directors do not receive an attendance fee for each board meeting, but an attendance fee of $1,000 is paid to each director for each committee meeting he attends, except the audit committee members who receive $1,250 for each audit committee meeting. Directors are also reimbursed for related out-of-pocket expenses. Each committee chairman receives $2,500 annually, except the audit committee chairman who receives $3,500 annually. Barry E. Davis, as an officer of Crosstex Energy GP, LLC, is otherwise compensated for his services and therefore receives no separate compensation for his service as a director. Messrs. Haden, Lawrence, Lubar, Murchison and Wells also received a one-time grant of 10,000 options at an exercise price of $20 in 2003 and Messr. Burke received a one-time grant of 10,000 options at an exercise price of $36.29 (the unit closing price on the date of the grant).

Compensation Committee Interlocks And Insider Participation

The Compensation Committee of the board of directors of Crosstex Energy GP, LLC determines compensation of the executive officers. Sheldon B. Lubar and Robert F. Murchison served as members of the Compensation Committee of the board of directors of Crosstex Energy GP, LLC upon the completion of our initial public offering.

Item 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters*

The following table shows the beneficial ownership of units of Crosstex Energy, L.P. as of February 28, 2004, held by:

- each person who beneficially owns 5% or more of the units then outstanding;
- all the directors of Crosstex Energy GP, LLC;
- each named executive officer of Crosstex Energy GP, LLC; and

- all the directors and executive officers of Crosstex Energy GP, LLC as a group.

Name of Beneficial Owner(1)	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned	Subordinated Units Beneficially Owned	Percentage of Subordinated Units Beneficially Owned	Percentage of Total Units Beneficially Owned
Crosstex Holdings, L.P	333,000	7.6%	4,667,000	100.0%	55.4%
Barry E. Davis(2)(3)	10,000	—	—	—	—
James R. Wales(2)(3)	6,667	—	—	—	—
A. Chris Aulds(2)(3)	6,667	—	—	—	—
Jack M. Lafield(2)(3)	5,833	—	—	—	—
William W. Davis(2)(3)	5,833	—	—	—	—
Michael P. Scott(2)(3)	4,167	—	—	—	—
Frank Burke	3,000	*	—	—	*
C. Roland Haden(4)	5,833	*	—	—	*
Bryan H. Lawrence(5)	—	—	—	—	—
Sheldon B. Lubar(6)	3,333	—	—	—	—
Stephen A. Wells	8,333	*	—	—	*
Robert F. Murchison(7)	28,333	*	—	—	*
All directors and executive officers as a group(3) (11 persons)	87,999	*	—	—	*

* Less than 1%.

(1) The address of each person listed above is 2501 Cedar Springs, Suite 600, Dallas, Texas 75201, except for Crosstex Holdings L.P. which is 3993 Howard Hughes Parkway Suite 250, Las Vegas, Nevada 89109 and Bryan H. Lawrence which is 410 Park Avenue, New York, New York 10022.

(2) Barry E. Davis, James R. Wales, A. Chris Aulds, Jack M. Lafield, William W. Davis and Michael P. Scott each hold an ownership interest in Crosstex Energy, Inc. as indicated in the following table.

(3) Ownership percentage for such individual or group includes common units issuable pursuant to options which are presently exercisable or exercisable within 60 days, including 10,000 units for Mr. Barry E. Davis, 6,667 units for Mr. Wales, 6,667 units for Mr. Aulds, 5,833 units for Mr. Lafield, 5,833 units for Mr. William W. Davis,

4,167 units for Mr. Scott, and 39,167 units for all directors and executive officers as a group.

(4) These units are held in a trust for the benefit of the Mr. Haden's children. Mr. Haden and his spouse are trustees of the trust.

(5) Bryan H. Lawrence is a member and a manager of the general partner of both Yorktown Energy Partners IV, L.P. and Yorktown Energy Partners V, L.P. Both of these limited partnerships own an interest in Crosstex Energy, Inc. as indicated in the following table.

(6) Sheldon B. Lubar is a general partner of Lubar Nominees, and Lubar Nominees holds an ownership interest in Crosstex Energy, Inc. as indicated in the following table.

(7) These units are held by Murchison Capital Partners, L.P. Mr. Murchison is the President of the Murchison Management Corp., which serves as the general partner of Murchison Capital Partners, L.P.

The following table shows the beneficial ownership of Crosstex Energy, Inc. as of February 28, 2004. Crosstex Energy, Inc. owns Crosstex Energy GP, LLC and, together with Crosstex Energy GP,

LLC, our general partner. Crosstex Energy, Inc. also owns Crosstex Holdings, L.P. and, as reflected above, Crosstex Holdings, L.P. owns common units and subordinated units.

Name of Beneficial Owner(1)	Common shares beneficially owned	Percent of equity beneficially owned
Yorktown Energy Partners IV, L.P.(2)	5,817,748	48.16%
Yorktown Energy Partners V, L.P.(2)	1,457,000	12.06%
Lubar Nominees(3)	697,498	5.77%
Barry E. Davis(4)	643,916	5.31%
James R. Wales(4)	306,762	2.52%
A. Chris Aulds(4)	383,268	3.16%
Jack M. Lafield(4)	59,305	*
William W. Davis(4)	58,269	*
Michael P. Scott(4)	48,917	*
Frank M. Burke	10,000	*
C. Roland Haden	—	—
Bryan H. Lawrence(5)	—	—
Sheldon B. Lubar(3)	697,498	5.77%
Stephen A. Wells	—	—
Robert F. Murchison	30,000	*
All directors and executive officers as a group (11 persons)(4)	2,237,895	18.11%

* Less than 1%.

(1) Unless otherwise indicated, the address of each person listed above is 2501 Cedar Springs, Suite 600, Dallas, Texas 75201.

(2) The address for Yorktown Energy Partners IV, L.P. and Yorktown Energy Partners V, L.P. is 410 Park Avenue, New York, New York 10022.

(3) Sheldon B. Lubar is a general partner of Lubar Nominees, and may be deemed to beneficially own the shares held by Lubar Nominees.

(4) Ownership percentage for such individual or group includes shares issuable pursuant to stock options which are presently exercisable or exercisable within 60 days including 40,000 shares for Mr. Barry E. Davis, 85,000 shares for Mr. Wales, 60,000 shares for Mr. Aulds, 31,003 shares for Mr. Lafield, 33,333 shares for Mr. William W. Davis, 26,667 shares for Mr. Scott and 276,003 shares for all directors and executive officers as a group.

(5) Bryan H. Lawrence is a member and a manager of the general partner of both Yorktown Energy Partners IV, L.P. and Yorktown Energy Partners V, L.P.

Beneficial Ownership of General Partner Interest

Crosstex Energy GP, L.P. owns all of our 2% general partner interest and all of our incentive distribution rights. Crosstex Energy GP, L.P. is owned 0.001% by its general partner, Crosstex Energy GP, LLC and 99.999%; by its sole limited partner, Crosstex Holdings, L.P.

Equity Compensation Plan Information

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants, And Rights (a)	Weighted-Average Price Of Outstanding Options, Warrants And Rights (b)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected In Column (a)) (c)
Equity Compensation Plans Approved By Security Holders	N/A	N/A	N/A
Equity Compensation Plans Not Approved By Security Holders	700,000(1)	$ 20.56(2)	329,289(3)

(1) Our general partner has adopted and maintains a Long Term Incentive Plan for our officers, employees and directors. See Item 11. "Executive Compensation—Long-Term Incentive Plan." The LTIP contemplates awards of up to 233,000 restricted units and 467,000 unit options.

(2) The strike prices for outstanding options under the plan as of December 31, 2003 range from $20.00 to $36.29 per unit.

(3) Consisting of 183,925 restricted units and 145,364 unit options.

Item 13. *Certain Relationships and Related Transactions*

Our General Partner

Our operations and activities are managed by, and our officers are employed by, the operating partnership. Our general partner does not receive any management fee or other compensation in connection with its management of our business, but it is reimbursed for all direct and indirect expenses incurred on our behalf. For the twelve months ended December 31, 2003, the amount which we reimbursed the 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 will 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 behalf of the partnership.

Our general partner owns the 2% general partner interest and all of the incentive distribution rights. Our general partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. 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.

Relationship with Crosstex Energy, Inc.

General. Crosstex Energy, Inc. indirectly owns 333,000 common units and 4,667,000 subordinated units representing an aggregate 54.3% limited partnership interest in us. Our general partner owns a 2% general partner interest in us and the incentive distribution rights. Our general partner's ability, as general partner, to manage and operate Crosstex Energy, L.P. and Crosstex Energy, Inc.'s ownership of an aggregate 56.3% limited partner interest in us effectively gives our general partner the ability to veto some of our actions and to control our management.

Omnibus Agreement. Concurrent with the closing of our initial public offering, we entered into an agreement with Crosstex Energy, Inc., Crosstex Energy GP, LLC and our general partner which will govern potential competition among us and the other parties to the agreement. Crosstex Energy, Inc. agreed, and caused its controlled affiliates to agree, for so long as management, Yorktown Energy Partners IV, L.P. and Yorktown Energy Partners V, L.P. and its affiliates, or any combination thereof, control our general partner, not to engage in the business of gathering, transmitting, treating, processing, storing and marketing of natural gas and the transportation, fractionation, storing and marketing of NGLs unless it first offers us the opportunity to engage in this activity or acquire this business, and the board of directors of Crosstex Energy GP, LLC, with the concurrence of its conflicts committee, elects to cause us not to pursue such opportunity or acquisition. In addition, Crosstex Energy, Inc. has the ability to purchase a business that has a competing natural gas gathering, transmitting, treating, processing and producer services business if the competing business does not represent the majority in value of the business to be acquired and Crosstex Energy, Inc. offers us the opportunity to purchase the competing operations following their acquisition. The noncompetition restrictions in the omnibus agreement do not apply to the assets retained and business conducted by Crosstex Energy, Inc. at the closing of our initial public offering. Except as provided above, Crosstex Energy, Inc. and its controlled affiliates are not prohibited from engaging in activities in which they compete directly with us. In addition, Yorktown Energy Partners IV, L.P., Yorktown Energy Partners V, L.P. and any affiliated Yorktown funds are not prohibited from owning or engaging in businesses which compete with us.

Related Party Transactions

Camden Resources, Inc. We treat gas for, and purchase gas from, Camden Resources, Inc. Yorktown Energy Partners IV, L.P. has made equity investments in both Camden and Crosstex Energy, Inc. The gas treating and gas purchase agreements we have entered into with Camden are standard industry agreements containing terms substantially similar to those contained in our agreements with other third parties. During the year ended December 31, 2003, we purchased natural gas from Camden Resources, Inc. in the amount of approximately $8.4 million and received approximately $190,000 in treating fees from Camden Resources, Inc.

Crosstex Pipeline Partners, L.P. We indirectly own general and limited partner interests in Crosstex Pipeline Partners, L.P. that represent a 28% economic interest. We have entered into various transactions with Crosstex Pipeline Partners, and we believe that the terms of these transactions are comparable to those that we could have negotiated with unrelated third parties. During the year ended December 31, 2003, our predecessor: (1) purchased natural gas from Crosstex Pipeline Partners in the amount of approximately $8.2 million and paid Crosstex Pipeline Partners approximately $41,000 for transportation of natural gas, (2) received a management fee from Crosstex Pipeline Partners in the amount of approximately $125,000 and (3) received approximately $104,000 in distributions from Crosstex Pipeline Partners

Crosstex Denton County Gathering J.V. We own a 50% interest in Crosstex Denton County Gathering, J.V. (CDC). CDC was formed to build, own and operate a natural gas gathering system in Denton County, Texas. We manage the business affairs of CDC. The other 50% joint venture partner (the CDC Partner) is an unrelated third party who owns and operates the natural gas field in Denton County.

In connection with the formation of CDC, we 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 us 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 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.

During the year ended December 31, 2003, the Partnership received a management fee from CDC of $110,000.

Item 14. *Principal Accountant Fees and Services*

The Audit Committee of the board of directors of Crosstex Energy GP, LLC has selected KPMG LLP ("KPMG") to continue as our independent auditors for the fiscal year ending December 31, 2004.

Audit Fees

The fees for professional services rendered for the audit of our annual financial statements for each of the fiscal years ended December 31, 2003 and December 31, 2002, and the reviews of the financial statements included in our Quarterly Reports on Forms 10-Q or services that are normally provided by KPMG in connection with statutory or regulatory filings or engagement for each of those fiscal years, were $411,500 and $354,123, respectively. These amounts also included fees associated with comfort letters and consents related to debt and equity offerings.

Audit-Related Fees

KPMG did not perform any assurance and related services related to the performance of the audit or review of our financial statements for the fiscal years ended December 31, 2003 and December 31, 2002 that were not included in the audit fees listed above.

Tax Fees

Aggregate fees billed or expected to be billed by KPMG, for tax compliance, tax advice and tax planning for each of the fiscal years ended December 31, 2003 and December 31, 2002, were $103,725 and $50,875, respectively. These fees include fees relating to reviews of tax returns, tax consulting and planning.

All Other Fees

KPMG did not render services to us, other than those services covered in the sections captioned "Audit Fees," and "Tax Fees" for the fiscal years ended December 31, 2003 and December 31, 2002.

Audit Committee Approval of Audit and Non-Audit Services

In 2003, the Audit Committee had not formally adopted any pre-approval polices and procedures relating to the provision of non-audit services by our independent auditors, KPMG. Instead, each type of non-audit service proposed to be provided by KPMG was approved on an individual basis by the Audit Committee in advance of the rendering of such non-audit services. For 2004, the Audit Committee has pre-approved the use of KPMG for specific tax-related services. In such case, the Audit Committee has also set a specific annual limit on the amount of such tax-related services which we will obtain from KPMG, and has required management to report the specific engagements to the Audit Committee. All other non-audit services other than the pre-approved services set forth above and any services that exceed the annual limits set forth in the policy must be pre-approved by the Audit Committee. The Chairman of the Audit Committee is authorized by the Audit Committee to pre-approve additional KPMG audit and non-audit services between Audit Committee meetings; provided that the additional services do not affect KPMG's independence under applicable Securities and Exchange Commission rules and any such pre-approval is reported to the Audit Committee at its next meeting.

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 KPMG LLP.
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.

* 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 8th day of March 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

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on the dates indicated by the following persons on behalf of the Registrant and in the capacities with Crosstex Energy GP, LLC, general partner of Crosstex Energy GP, L.P., general partner of the Registrant, indicated.

Signature	Title	Date
/s/ BARRY E. DAVIS Barry E. Davis	President, Chief Executive Officer and Director (Principal Executive Officer)	March 8, 2004
/s/ FRANK M. BURKE Frank M. Burke	Director	March 8, 2004
/s/ C. ROLAND HADEN C. Roland Haden	Director	March 8, 2004
/s/ BRYAN H. LAWRENCE Bryan H. Lawrence	Chairman of the Board	March 8, 2004
/s/ SHELDON B. LUBAR Sheldon B. Lubar	Director	March 8, 2004
/s/ ROBERT F. MURCHISON Robert F. Murchison	Director	March 8, 2004
/s/ STEPHEN A. WELLS Stephen A. Wells	Director	March 8, 2004
/s/ WILLIAM W. DAVIS William W. Davis	Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	March 8, 2004

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Independent Auditors' Report

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 auditing standards generally accepted in the United States of America. 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 1 to the consolidated financial statements, effective January 1, 2001, the Partnership changed its method of accounting for derivatives. Also, as explained in note 2 to the consolidated financial statements, effective January 1, 2002, the Partnership changed its method of amortizing goodwill.

/s/ KPMG LLP

Dallas, Texas
February 26, 2004

CROSSTEX ENERGY, L.P.

Consolidated Balance Sheets

December 31, 2003 and 2002

(In thousands)

	2003	2002
Assets		
Current assets:		
Cash and cash equivalents	$ 166	$ 1,308
Accounts receivable:		
Trade	9,491	26,302
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	145,421	110,998
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	$ 365,303	$ 232,438
Liabilities and Partners' Equity		
Current liabilities:		
Drafts payable	$ 10,446	$ 27,546
Accounts payable	4,064	8,479
Accrued gas purchases	119,756	74,768
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	148,335	119,670
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)	117,366	58,147
Subordinated unit-holders (4,667,000 units issued and outstanding at December 31, 2003 and 2002)	34,632	31,829
General partner interest (2% interest with 184,000 and 149,000 equivalent units outstanding at December 31, 2003 and 2002, respectively)	2,887	1,016
Accumulated other comprehensive income (loss)	1,383	(1,176)
Total partners' equity	156,268	89,816
Total liabilities and partners' equity	$ 365,303	$ 232,438

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Operations

(In thousands)

	Years ended December 31,		
	2003	**2002**	**2001**
Revenues:			
Midstream	$ 993,140	$ 437,676	$ 362,673
Treating	20,523	14,817	24,353
Total revenues	1,013,663	452,493	387,026
Operating costs and expenses:			
Midstream purchased gas	946,412	413,982	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)	(2,703)	3,714
Depreciation and amortization	13,268	7,745	6,101
Total operating costs and expenses	995,224	447,929	388,865
Operating income (loss)	18,439	4,564	(1,839)
Other income (expense):			
Interest expense, net	(3,392)	(2,717)	(2,253)
Other income	179	155	174
Total other income (expense)	(3,213)	(2,562)	(2,079)

Net income (loss)	$ 15,226	$ 2,002	$ (3,918)
Allocation of 2002 net income:			
Net income for the period from January 1, 2002 to December 16, 2002	—	$ 1,682	—
Net income for the period from December 17, 2002 to December 31, 2002	—	320	—
Net income	—	$ 2,002	—
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, 2002 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	1,682	—	—	—	—	1,682
Distributions	(2,500)	—	—	—	—	(2,500)
Transfer of equity in accordance with initial public offering	(50,482)	17,844	31,628	1,010	—	—
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	—	58,147	31,829	1,016	(1,176)	89,816
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	$ —	$ 117,366	$ 34,623	$ 2,887	$ 1,383	$ 156,268

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	2001
Net income (loss)	$ 15,226	$ 2,002	$ (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	$ 684	$ (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	2001
Cash flows from operating activities:			
Net income (loss)	$ 15,226	$ 2,002	(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)	(46,544)	47,565
Prepaid expenses	(754)	178	(1,566)
Accounts payable, accrued gas purchases, and other accrued liabilities	41,084	28,799	(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.

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements

December 31, 2003 and 2002

(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) 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 (in thousands).

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:

	Year ended December 31,		
	2003	2002	2001
Net income, as reported	$ 15,226	$ 2,002	(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	$ 1,715	(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.

(3) 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
Revenue	$	1,119,985	$	589,748
Net income		16,216		4,004
Net income per limited partner unit	$	1.90		—

(4) 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

(5) 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 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.

(6) 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.

(7) 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.

(8) 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.

(9) Fair Value of Financial Instruments

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

	2003		2002	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Cash and cash equivalents	$ 166	$ 166	$ 1,308	$ 1,308
Trade accounts receivable and accrued revenues	134,008	134,008	104,802	104,802
Fair value of derivative assets	4,080	4,080	3,102	3,102
Accounts payable, drafts payable and accrued gas purchases	134,266	134,266	110,793	110,793
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.

(10) 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.

(11) 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.

(12) 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.

(13) 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:			
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	322,780	45,523	365,303
Capital expenditures	28,728	10,275	39,003
Year ended December 31, 2002:			
Sales to external customers	$ 437,676	$ 14,817	$ 452,493
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)	3,271	(1,269)	2,002
Segment assets	199,056	33,382	232,438
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

(14) Quarterly Financial Data (Unaudited)

Summarized un-audited quarterly financial data is presented below.

	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	$ 80,993	$ 126,480	$ 114,611	$ 130,409	$ 452,493
Operating income	4,681	5,468	6,182	5,945	22,276
Net income (loss)	(252)(1)	224	1,485	545(1)(2)	2,002

(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.

(15) 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.

Schedule II

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.

Exhibit 10.3

SECOND AMENDMENT

THIS SECOND AMENDMENT TO SECOND AMENDED AND RESTATED CREDIT AGREEMENT (this "*Amendment*") is entered into this 30th day of October, 2003 by and among the persons executing this Amendment as banks (the "*Banks*"), Crosstex Energy Services, L.P., a Delaware limited partnership (the "*Borrower*"), and Union Bank of California, N.A., as administrative agent (the "*Administrative Agent*").

BACKGROUND

A. The Banks, the Administrative Agent and the Borrower are parties to that certain Second Amended and Restated Credit Agreement dated as of November 26, 2002, as amended by the First Amendment dated as of June 3, 2003 (said Agreement, as so amended, herein called the "*Credit Agreement*"). Terms defined in the Credit Agreement and not otherwise defined herein have the same respective meanings when used herein.

B. The Borrower has requested, and the Banks have agreed, to increase the aggregate amount of the Revolver B Commitments to $50,000,000 and make certain other amendments to the Credit Agreement.

C. In addition, the parties hereto wish to add Bank of America, N.A. as a "Bank" under the Credit Agreement (the "*New Bank*").

AGREEMENT

NOW THEREFORE, in connection of the covenants, conditions and agreements hereafter set forth, and for other good and valuable consideration, the receipt and adequacy of which are all hereby acknowledged, the parties hereto covenant and agree as follows:

Section 1. *Amendments*.

(a) Schedules 1 and 2 to the Credit Agreement are hereby deleted in their entirety and Schedules 1 and 2 attached hereto are hereby substituted therefor.

(b) Section 2.01(b) of the Credit Agreement is hereby amended by replacing "$10,000,000" with "$25,000,000" in the second proviso of the first sentence thereof.

(c) Section 2.06(d) of the Credit Agreement is hereby deleted in its entirety.

Section 2. *Conditions Precedent*. This Amendment shall become effective as of the date first set forth above when:

(a) the Borrower shall have paid to the Administrative Agent for the account of each Bank (other than the New Bank) a non-refundable amendment fee of $5,000.00 and all costs and expenses which have been invoiced and are payable pursuant to Section 9.04 of the Credit Agreement;

(b) all of the following, each dated the date hereof, in form and substance satisfactory to the Administrative Agent and in the number of originals requested by the Administrative Agent:

(i) this Amendment, duly executed by the Borrower, the Banks, the Administrative Agent, the Syndication Agent and the Documentation Agent;

(ii) new Revolver A Notes in favor of each of the Banks, each in the face amount of such Bank's Revolver A Commitment and duly executed by the Borrower (the "*New Revolver A Notes*");

(iii) new Revolver B Notes in favor of each of the Banks, each in the face amount of such Bank's Revolver B Commitment and duly executed by the Borrower (the "*New Revolver B Notes*"; together with the New Revolver A Notes, the "*New Notes*");

(iv) one or more consents to this Amendment, duly executed by each Guarantor that has previously executed a Guaranty;

(v) written consent to this Amendment, duly executed by Required Holders (as defined in the Note Agreement);

(vi) a certificate from a Responsible Officer stating that (A) all representations and warranties of the Borrower set forth in the Credit Agreement and each of the other Credit Documents to which it is a party are true and correct in all material respects, except to the extent any such representation or warranty is stated to relate solely to an earlier date, in which case such representation or warranty shall have been true and correct on such earlier date; (B) no Default has occurred and is continuing; and (C) the conditions in this Section 2 have been met;

(vii) a certificate of the secretary or assistant secretary of the General Partner certifying as of the date of this Amendment (A) the existence of the Borrower and the General Partner, (B) that there have been no changes to its organizational documents or the Borrower Partnership Agreement since the Effective Date, (C) the resolutions of the General Partner approving this Amendment, and (D) all documents evidencing other necessary corporate, partnership or limited liability company action and governmental approvals, if any, with respect to this Amendment and the other Credit Documents executed and delivered on or before the date hereof;

(viii) a certificate of the secretary or assistant secretary of each of the Guarantors certifying as of the date of this Amendment (A) that there have been no changes to its organizational documents since the Effective Date, (B) the resolutions of the governing body of such Guarantor approving this Amendment, and (C) all documents evidencing other necessary corporate, partnership or limited liability company action and governmental approvals, if any, with respect to this Amendment and the other Credit Documents executed and delivered on or before the date hereof;

(ix) certificates of good standing, existence and authority for the Borrower, the General Partner and each of the Guarantors from each of the states in which the Borrower, the General Partner and each of the Guarantors is organized; and

(x) such other approvals, opinions, evidence and documents as any Bank, through the Administrative Agent, may reasonably request.

(c) no event or events has occurred which, individually or in the aggregate, have had or could reasonably be expected to have a Material Adverse Effect;

(d) no Default shall have occurred and be continuing;

(e) the representations and warranties of the Borrower and the Guarantors contained in this Amendment, Article IV of the Credit Agreement and in each of the other Credit Documents executed and delivered on or before date hereof shall be true and correct in all material respects on and as of the date hereof, except to the extent any such representation or warranty is stated to relate solely to an earlier date, in which case such representation or warranty shall have been true and correct on such earlier date; and

(f) no legal or regulatory action or proceeding has commenced and is continuing against the Borrower or any Guarantor which could reasonably be expected to cause a Material Adverse Effect.

Section 3. *Representations and Warranties*. The Borrower represents and warrants to the Banks and the Administrative Agent as set forth below:

(a) The execution, delivery and performance by the Borrower of this Amendment, the New Notes and the Credit Documents, as amended hereby and thereby, to which the Borrower is a party are within the Borrower's legal powers, have been duly authorized by all necessary partnership action and do not (i) contravene the Borrower Partnership Agreement, (ii) contravene any Governmental Rule or contractual restriction binding on or affecting the Borrower or (iii) result in or require the creation or imposition of any Lien (other than any created by the Credit Documents) upon or with respect to any of the properties of the Borrower.

(b) No Governmental Action is required for the due execution, delivery or performance by the Borrower or this Amendment, the New Notes or any of the Credit Documents, as amended hereby and thereby, to which the Borrower is a party.

(c) This Amendment, the New Notes and each of the Credit Documents, as amended hereby and thereby, to which the Borrower is a party constitute legal, valid and binding obligations of the Borrower, enforceable against the Borrower in accordance with their respective terms, except as the enforceability thereof may be limited by bankruptcy, insolvency, moratorium, reorganization or other similar laws affecting creditors' rights generally or by general principles of equity.

(d) Each of the Security Documents constitutes an Acceptable Security Interest on the Collateral purported to be encumbered thereby, enforceable against all third parties in all jurisdictions, and secures the payment of all obligations stated to be secured thereby under the Credit Documents, as amended hereby and by the New Notes, and the execution, delivery and performance of this Amendment and the New Notes do not adversely affect any Lien of the Collateral Documents.

(e) The quarterly and annual financial statements most recently delivered to the Banks pursuant to Sections 5.01(c) and (d) of the Credit Agreement fairly present the Consolidated financial condition of the Borrower and its Subsidiaries as of the respective dates thereof and the Consolidated results of the operations of the Borrower and its Subsidiaries for the respective fiscal periods ended on such dates, all in accordance with GAAP applied on a consistent basis (subject to normal year-end audit adjustments). Since December 31, 2002 there has been no material and adverse change in the business, condition (financial or otherwise), operations, performance, properties or prospects of the Borrower or any Subsidiary. The Borrower and its Subsidiaries have no material contingent liabilities except as disclosed in such financial statements or the notes thereto.

(f) There is no pending or, to the knowledge of the Borrower, threatened action or proceeding affecting the Borrower or any Subsidiary before any Governmental Person, referee or arbitrator that could reasonably be expected to have a Material Adverse Effect.

(g) There has been no amendment to the Borrower Partnership Agreement. The representations and warranties of the Borrower contained in the Credit Documents are correct on and as of the date hereof as though made on and as of such date except to the extent any such representation or warranty is stated to relate solely to an earlier date, in which case such representation or warranty shall have been true and correct on such earlier date. No event has occurred and is continuing, or would result from the effectiveness of this Amendment, that constitutes a Default.

Section 4. *Modification and Increase in Commitments*. The Borrower, the Administrative Agent, and the Banks hereby agree that the Commitments of the Banks under the Credit Agreement shall be modified to reflect the Commitments for the Banks set forth on the attached Schedule 1 and upon the effectiveness of this Agreement pursuant to Section 2 above, each such Bank's Commitment shall be

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the Commitment set forth on the attached Schedule 1. On the date here, the New Bank shall pay to the Administrative Agent, for the account of the Banks (other than the New Bank) an amount equal to the New Bank's Pro Rata Share of the outstanding Advances. Such payment shall be made by wire transfer of immediately available funds to an account designated by the Administrative Agent. Upon receipt of such funds, the Administrative Agent shall promptly pay to each Bank, by wire transfer in immediately available funds, the amount of each such Bank's ratable share of such payment, such that after such payment, the Banks (including the New Bank) shall each hold its Pro Rata Share of the Advances.

Section 5. *Addition of New Bank*. The New Bank (i) confirms that it has received a copy of the Credit Agreement, together with copies of the financial statements referred to in Section 4.05 and 5.01 thereof and such other documents and information as it has deemed appropriate to make its own credit analysis and decision to enter into this Amendment; (ii) agrees that it will, independently and without reliance upon the Administrative Agent or any other Bank and based on such documents and information as it shall deem appropriate at the time, continue to make its own credit decisions in taking or not taking action under the Credit Agreement or any other Credit Document; (iii) appoints and authorizes the Administrative Agent and the Collateral Agent to take such action as agent on its behalf and to exercise such powers as it deems necessary under the Credit Agreement and any other Credit Document as are delegated to the Administrative Agent or the Collateral Agent by the terms thereof, together with such powers as are reasonably incidental thereto; (iv) agrees that it will perform in accordance with their terms all of the obligations which by the terms of the Credit Agreement or any other Credit Document are required to be performed by it as a Bank; and (v) specifies as its Domestic Lending Office (and address for notices) the office set forth beneath its name on Schedule 2 hereto.

Section 6. *Reference to and Effect on the Credit Agreement*.

(a) On and after the effective date of this Amendment, each reference in the Credit Agreement to "this Agreement," "hereunder," "hereof," "herein" or words of like import shall mean and be a reference to the Credit Agreement, and each reference in the other Credit Documents to "the Credit Agreement," "thereunder," "thereof," "therein" or words of like import referring to the Credit Agreement, shall mean and be a reference to the Credit Agreement as amended by this Amendment.

(b) Except as specifically amended above and except for the issuance of the New Notes, the Credit Agreement and the other Credit Documents shall remain in full force and effect and are hereby ratified and confirmed. Without limiting the generality of the foregoing, the Collateral Documents and all of the Collateral described therein do and shall continue to secure the payment of all obligations stated to be secured thereby under the Credit Documents, as amended hereby and by the New Notes.

(c) Except as expressly set forth herein, the execution, delivery and effectiveness of this Amendment shall not operate as a waiver of any right, power or remedy of the Administrative Agent or any Bank under any of the Credit Documents or constitute a waiver of any provision of any of the Credit Documents.

Section 7. *Execution in Counterparts.* This Amendment may be executed in any number of counterparts and by the parties hereto in separate counterparts, each which when so executed and delivered shall be deemed to be an original and all of which when taken together shall constitute but one and the same instrument. Delivery of an executed counterpart of a signature page to this Amendment by telecopier shall be effective as delivery of an originally executed counterpart of this Amendment.

Section 8. *Governing Law; Binding Effect.* This Amendment shall be governed by, and construed and enforced in accordance with, the laws of the State of Texas, and shall be binding upon the Borrower, the Administrative Agent, each Bank and their respective successors and assigns.

Section 9. *Costs and Expenses*. The Borrower agrees to pay on demand all costs and expenses of the Administrative Agent in connection with the preparation, execution and delivery of this Amendment and the other instruments and documents to be delivered hereunder, including the reasonable fees and out-of-pocket expenses of counsel for the Administrative Agent with respect thereto and with respect to advising the Administrative Agent as to its rights and responsibilities hereunder and thereunder.

Effective as of the 30th day of October, 2003.

CROSSTEX ENERGY SERVICES, L.P.

By: CROSSTEX ENERGY SERVICES GP, LLC,
General Partner

By: /s/ WILLIAM W. DAVIS

William W. Davis
Senior Vice President and Chief
Financial Officer

UNION BANK OF CALIFORNIA, N.A.,
as Lead Arranger, Administrative Agent and Bank

By: /s/ JOHN CLARK

Name: John Clark

Title: Vice President

By: /s/ RANDALL OSTERBERG

Name: Randall Osterberg

Title: Senior Vice President

THE ROYAL BANK OF CANADA,
as Co-Arranger, Syndication Agent and Bank

By: /s/ LORNE GARTNER

Name: Lorne Gartner

Title: Attorney-in-Fact

FLEET NATIONAL BANK,
as Documentation Agent and Bank

By: /s/ ALLISON I. ROSSI

Name: Allison I. Rossi

Title: Director

U.S. BANK NATIONAL ASSOCIATION,
as Bank

By:	/s/ MATTHEW J. PURCHASE
Name:	Matthew J. Purchase
Title:	Vice President

BANK OF AMERICA, N.A.,
as Bank

By:	/s/ STEVEN A. MACKENZIE
Name:	Steven A. Mackenzie
Title:	Vice President

SCHEDULE 1

COMMITMENTS

Bank		Revolver A Commitment		Revolver B Commitment
Union Bank of California, N.A.	$	16,625,000.00	$	11,875,000.00
Fleet National Bank	$	16,625,000.00	$	11,875,000.00
The Royal Bank of Canada	$	14,000,000.00	$	10,000,000.00
U.S. Bank National Association	$	11,375,000.00	$	8,125,000.00
Bank of America, N.A.	$	11,375,000.00	$	8,125,000.00
TOTALS	$	70,000,000.00	$	50,000,000.00

SCHEDULE 2

APPLICABLE LENDING OFFICES; ADDRESS FOR NOTICES

Bank	Domestic and Eurodollar Lending Offices
Union Bank of California, N.A.	445 South Figueroa Street, Suite 1502 Los Angeles, California 90071 Telecopier: 213-236-5747 Attention: Energy Capital Services
The Royal Bank of Canada	New York Branch One Liberty Plaza, 3rd Floor New York, NY 10006-1404 Telephone: (212) 428-6332 Telecopier: (212) 428-2372 Attention: Compton Singh, Liability Officer With a copy to: 5700 Williams Tower 2800 Post Oak Blvd. Houston, Texas 77056 Phone: 713-899-0234 Fax: 713-899-5624 Attention: Lorne Gartner
Fleet National Bank	100 Federal Street Mail Stop MADE 10008A Boston, Massachusetts 02110 Telecopier: 617-434-3652 Attention: Allison Rossi
U.S. Bank National Association	918 17th Street, 3rd Floor Denver, Colorado 80202 Telecopier: 303-585-4362 Attention: Matthew Purchase

Bank of America, N.A.	TX1-492-67-01 901 Main Street, 67th Floor Dallas, Texas 75202-3714 Telecopier: 214-209-3140 Attention: Steven A. MacKenzie

	Address for Notices
Crosstex Energy Services, L.P.	2501 Cedar Springs, Suite 600 Dallas, Texas 75201 Telephone: 214-953-9500 Telecopier: 214-953-9501 Attention: Mr. William W. Davis
Union Bank of California, N.A.	445 South Figueroa Street, Suite 1502 Los Angeles, California 90071 Telecopier: 213-236-5747 Attention: Energy Capital Services With a copy to: 4200 Lincoln Plaza 500 N. Akard Street Dallas, Texas 75201 Telecopier: 214-922-4209 Attention: John Clark, Vice President
The Royal Bank of Canada	New York Branch One Liberty Plaza, 3rd Floor New York, NY 10006-1404 Telephone: (212) 428-6332 Telecopier: (212) 428-2372 Attention: Compton Singh, Liability Officer With a copy to: 5700 Williams Tower 2800 Post Oak Blvd. Houston, Texas 77056 Phone: 713-899-0234 Fax: 713-899-5624 Attention: Lorne Gartner
Fleet National Bank	100 Federal Street Mail Stop MADE 10008A Boston, Massachusetts 02110 Telecopier: 617-434-3652 Attention: Allison Rossi
U.S. Bank National Association	918 17th Street, 3rd Floor Denver, Colorado 80202 Telecopier: 303-585-4362 Attention: Matthew Purchase
Bank of America, N.A.	TX1-492-67-01 901 Main Street, 67th Floor Dallas, Texas 75202-3714 Telecopier: 214-209-3140 Attention: Steven A. MacKenzie

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Exhibit 21.1

List of Subsidiaries

Name of Subsidiary	State of Organization
Crosstex Energy Services GP, LLC	Delaware
Crosstex Energy Services, L.P.	Delaware
Crosstex Pipeline, LLC	Texas
Crosstex Pipeline Partners, L.P.	Texas
Crosstex Gulf Coast Transmission, Ltd.	Texas
Crosstex Gulf Coast Marketing, Ltd.	Texas
Crosstex CCNG Gathering Ltd.	Texas
Crosstex CCNG Marketing Ltd.	Texas
Crosstex CCNG Transmission Ltd.	Texas
Crosstex CCNG Processing Ltd.	Texas
Crosstex Treating Services, L.P.	Delaware
Crosstex Treating Services GP, LLC	Delaware
Crosstex Acquisition Management GP, LLC	Delaware
Crosstex Alabama Gathering System, L.P.	Delaware
Crosstex Mississippi Industrial Gas Sales, L.P.	Delaware
Crosstex Mississippi Pipeline, L.P.	Delaware
Crosstex Seminole Gas, L.P.	Delaware
Crosstex Acquisition Management, L.P.	Delaware

QuickLinks

Exhibit 21.1

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Exhibit 23.1

Independent Auditors' Consent

The Partners
Crosstex Energy, L.P.:

We consent to the incorporation by reference in the registration statement (No. 333-107025) on Form S-8 of Crosstex Energy, L.P. of our report dated February 26, 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 of Crosstex Energy, L.P. Our report refers to a change in accounting for derivatives and a change in the method of amortizing goodwill.

/s/ KPMG LLP
Dallas, Texas
March 8, 2004

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Exhibit 31.1

CERTIFICATION

I, Barry E. Davis, certify that:

1. I have reviewed this annual report on Form 10-K 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: March 8, 2004	/s/ BARRY E. DAVIS
	Barry E. Davis, *President and Chief Executive Officer* *(principal executive officer)*

Exhibit 31.2

CERTIFICATIONS

I, William W. Davis, certify that:

1. I have reviewed this annual report on Form 10-K 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: March 8, 2004	/s/ WILLIAM W. DAVIS
	William W. Davis, *Executive Vice President and Chief Financial Officer* *(principal financial and accounting officer)*

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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 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

March 8, 2004

/s/ WILLIAM W. DAVIS

William W. Davis
Chief Financial Officer

March 8, 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.

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