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, 2004**
OR

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

Commission file number: 000-50067

CROSSTEX ENERGY, L.P.
(Exact name of registrant as specified in its charter)

Delaware	**16-1616605**
(State of organization)	*(I.R.S. Employer Identification No.)*
2501 CEDAR SPRINGS **DALLAS, TEXAS**	**75201**
(Address of principal executive offices)	*(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 (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark 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 $210,768,677 on June 30, 2004, based on $26.40 per unit, the closing price of the Common Units as reported on the NASDAQ National Market on such date.

At March 4, 2005, there were outstanding 8,764,480 Common Units and 9,334,000 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, Dallas, Texas 75201, and our telephone number is (214) 953-9500. Our Internet address is www.crosstexenergy.com. In the Investor Information section of our web site, we post the following filings as soon as reasonably practicable after they are electronically filed with or furnished to the Securities and Exchange Commission: our annual report on Form 10-K; our quarterly reports on Form 10-Q; our current reports on Form 8-K; and any amendments to those reports or statements filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended. All such filings on our web site are available free of charge. 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 4,500 miles of natural gas gathering and transmission pipelines, five natural gas processing plants, and approximately 90 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 gathering and transmission 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 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 acquisitions since January 2000.

Acquisition	Acquisition Date	Purchase Price (In thousands)	Asset Type
Provident City Plant	February 2000	$ 350	Treating plants
Will-O-Mills (50%)	February 2000	2,000	Treating plants
Arkoma Gathering System	September 2000	10,500	Gathering pipeline
Gulf Coast System	September 2000	10,632	Gathering and transmission pipeline
CCNG Acquisition	May 2001	30,003	Gathering and transmission pipeline and processing plant
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
Pandale System	June 2002	2,156	Gathering pipeline
KCS McCaskill Pipeline	June 2002	250	Pipeline segment
Vanderbilt System	December 2002	12,000	Gathering and transmission pipeline
Will-O-Mills (50%)	December 2002	2,200	Treating plant
DEFS Acquisition	June 2003	68,124	Gathering and transmission systems and processing plants
LIG Acquisition	April 2004	73,692	Gathering and transmission systems, processing plants
Crosstex Pipeline Partners	December 2004	5,203	Gathering pipeline

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. We will also build new assets in response to producer and market needs, such as our recently announced North Texas Pipeline project as discussed in "Recent Acquisitions and Expansion" below. We believe the expanded scope of our operations, combined with a continued high level of drilling in our principal geographic areas, should present opportunities for continued expansion in our existing areas of operation as well as opportunities to acquire or develop 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 or development of key assets that will serve as a platform for further growth both through additional acquisitions and the construction of new assets. We established two new core areas through the acquisition of the Mississippi pipeline system in 2003 and the acquisition of the LIG pipeline system in 2004. These systems provide us with platforms to develop a significant presence in the south central Mississippi area and in Louisiana. We have pending before the Federal Energy Regulatory Commission the approval of abandonment from interstate service of 500 miles of interstate pipeline currently owned by Transco located in south Texas. If the abandonment is approved, we will acquire the system and two related systems, for a total of approximately $30 million.

- *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 more fully utilize the system's capacity. Many of our recently acquired systems have excess capacity that provide 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. Since treating services are not provided by many of our competitors, we have an additional advantage in competing for new supply when gas requires treating to meet pipeline specifications. 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, 2004, approximately 76% of our on-system natural gas sales were to industrial end users and utilities.

- *Undertaking construction and expansion opportunities ("organic growth").* 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, which has driven the growth of the Treating division in recent years. Additionally, in 2004 we significantly expanded the capacity of our Vanderbilt system from 65,000 MMBtu/d to over 100,000 MMBtu/d to service one of our major customers. We also constructed nine miles of pipeline to connect an area of new production in McMullen County of south Texas to our Corpus Christi system, which has given us access on a long-term basis to a significant new gas supply (65,000 MMBtu/d in the fourth quarter of 2004). We recently announced a new 122-mile pipeline construction project to move gas from an area near Fort Worth, Texas, where recent drilling activity in the Barnett Shale formation has expanded production beyond the existing infrastructure capability.

Recent Acquisitions and Expansion

LIG Pipeline Company. We acquired the LIG Pipeline Company and its subsidiaries from American Electric Power ("AEP") for $73.7 million on April 1, 2004. The acquisition increased our pipeline miles by approximately 2,000 miles, to a total of 4,500 pipeline miles, and increased our average pipeline throughput by approximately 603,000 MMBtu/d for the nine months ended December 31, 2004. The acquisition also added significant processing assets to the Partnership, particularly the Plaquemine and Gibson plants, which processed an average of 321,000 MMBtu/d in the fourth quarter. The acquisition was the largest in our history.

North Texas Pipeline Project. In February 2005, we announced that we have entered into agreements to construct a 122-mile pipeline and associated gathering lines from an area near Fort Worth, Texas into new markets accessed by the NGPL pipeline system. Drilling success in the Barnett Shale formation in the area has expanded production beyond the capacity of the existing pipeline infrastructure to efficiently access markets. Capital cost to construct the pipeline and associated facilities are estimated to be approximately $98 million, with completion estimated in the first quarter of 2006.

Other Developments

Two-For-One Split of Limited Partnership Units. On March 16, 2004, we completed a two-for-one split of our outstanding limited partnership units. All unit amounts in this Annual Report on Form 10-K reflect post-split units.

Bank Credit Facility. In June 2003, we 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. In conjunction with the LIG acquisition on April 1, 2004, the facility was increased to a total of $200 million, consisting of a $100 million acquisition facility, and a $100 million working capital and letter of credit facility.

Senior Secured Notes. In 2003, we entered into a master shelf agreement with an institutional lender pursuant to which we issued $40.0 million of senior secured notes with an interest rate of 6.93% and a maturity of seven years. In June 2004, we completed a private placement offering of $75.0 million of senior secured notes pursuant to this master shelf agreement, as amended, with an interest rate of 6.96% and a maturity of ten years. We used the net proceeds from the senior notes offerings to repay indebtedness under our 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 and in Louisiana, which, in the aggregate, consist of approximately 4,500 miles of pipeline and five processing plants and contributed approximately 77% and 73% of our gross profit in 2004 and 2003, respectively.

- *LIG System.* We acquired the LIG system on April 1, 2004. The LIG system is the largest intrastate pipeline system in Louisiana, consisting of 2,000 miles of gathering and transmission pipeline, and had an average throughput of approximately 603,000 MMBtu/d for the nine months ended December 31, 2004. The system also includes five processing plants with an average throughput of 294,000 MMBtu/day for the nine months ended December 31, 2004. The system has access to both rich and lean gas supplies. These supply locations range from north Louisiana to offshore production in southeast Louisiana. LIG has a variety of transportation and industrial sales customers, with the majority of its sales being made into the Mississippi River industrial corridor between Baton Rouge and New Orleans. LIG sells the production from approximately 117 gas producers to approximately 58 different customers in its markets.

- *Gulf Coast System.* We acquired the Gulf Coast system in September 2000. It is an intrastate pipeline system consisting of approximately 515 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 have recently converted a section of the Gulf Coast system to rich gas service, and added it to our Vanderbilt system (see "Vanderbilt System" below).

  The Gulf Coast system connects to gathering systems which collect natural gas from approximately 125 receipt points and has three delivery laterals which deliver natural gas directly to large industrial and utility consumers along the Gulf Coast. As of December 31, 2004, we were purchasing gas from over 93 producers primarily pursuant to month-to-month contracts and were reselling the natural gas to approximately 21 customers primarily pursuant to short-term or month-to-month arrangements. For the year ended December 31, 2004, approximately 89% of the natural gas volumes 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 were sold at a fixed price relative to an index. The Gulf Coast system had average throughput of approximately 72,000 MMBtu/d for the year ended December 31, 2004.

- *Vanderbilt System.* Our Vanderbilt system consists of approximately 180 miles of gathering and transmission pipelines located in Wharton and Fort Bend Counties near our Gulf Coast system. We have converted a section of pipeline previously considered part of our Gulf Coast system into rich gas service in conjunction with the Vanderbilt system to provide additional volumes to our major customer on the system. Natural gas is supplied to the system from over 32 receipt points. Prior to our acquisition, the gas had been sold to the Exxon Katy plant. In June 2003, we reversed the flow of gas and began deliveries to a customer's large processing plant at Point Comfort, Texas. The Vanderbilt system had average throughput of approximately 68,000 MMBtu/d for the year ended December 31, 2004.

The gas in the Vanderbilt system is now sold under a ten-year agreement, primarily to one customer, which began in June 2003 to supply up to 60,000 MMBtu/d. The agreement was modified in 2004 and again in 2005 to expand the volumes to be supplied under the agreement to 90,000 MMBtu/d. The gas is sold 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 39% 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.

- *Corpus Christi System.* The Corpus Christi system is an intrastate pipeline system consisting of approximately 355 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, for an aggregate purchase price of approximately $30 million.

Natural gas is supplied to the Corpus Christi system from approximately 47 receipt points, including treating and processing plants and third-party gathering systems and pipelines. The average throughput on this system was approximately 179,000 MMBtu/d for the year ended December 31, 2004.

In June 2002, we acquired from Florida Gas Transmission approximately 70 miles of 20-inch transmission line which allowed us to access new markets within Texas and to interconnect to the Florida Gas system within Texas (the “Hallmark lateral”). We have constructed an addition to the Hallmark lateral 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, and to 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 Transmission mainline. With this connection, we began selling gas into the markets served by the Florida Gas system and sold approximately 103,000 MMBtu/d for the year ended December 31, 2004.

As of December 31, 2004, we were purchasing natural gas for our Corpus Christi system from approximately 42 producers generally on month-to-month or short-term arrangements. For the year ended December 31, 2004, 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, 2004, we were selling gas to over 30 customers. For the year ended December 31, 2004, substantially 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 245 miles of pipeline ranging in diameter from two inches to 18 inches. The gathering system had average throughput of approximately 133,000 MMBtu/d for the year ended December 31, 2004 compared to an average throughput of approximately 151,000 MMBtu/d of gas per day in 2003.

As of December 31, 2004, we were purchasing gas from over 48 producers primarily pursuant to month-to-month contracts, and for the year ended December 31, 2004, approximately 96% 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, 2004. At the time of acquisition, the plant was processing approximately 43,400 MMBtu/d of gas per day.

For the year ended December 31, 2004, we purchased a small amount (approximately 12%) 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. 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. We purchased the remaining gas, approximately 88% 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 with no risk of loss or gain in processing the natural gas. Under these contracts, the producer retains ownership of the recovered 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. The Arkoma gathering system is approximately 140 miles in length and ranges in diameter from two to 10 inches and includes 8,500 horsepower of compression from three compressor stations. This low-pressure system gathers gas from approximately 215 wells for delivery to a mainline transmission system. The Arkoma system had an average throughput of 19,000 MMBtu/d for the year ended December 31, 2004.

  For the year ended December 31, 2004, we received a percentage of the proceeds from the sale of the natural gas to the mainline transmission pipeline for 49% of the volume on the Arkoma gathering system. Therefore, on that portion of the gas, our margins were a function of the price of gas. The remaining 51% of the gas was purchased at a fixed discount to an index price. 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 in June 2003. 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 603 miles of pipeline ranging in diameter from four to 20 inches. Average throughput on this system was approximately 78,000 MMBtu/d for the year ended December 31, 2004.

  We purchase gas from approximately 52 producers at the delivery points into the system and sold it to approximately 23 customers. Substantially all natural gas volumes are purchased at a fixed price relative to an index.

- *Conroe Gas Plant And Gathering System.* We acquired the Conroe gas plant and gathering system in June 2003 in connection with the acquisition of the Mississippi pipeline system. 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 approximately 18 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. Average throughput on this system was approximately 25,000 MMBtu/d for the year ended December 31, 2004. We generate operating profits at our Conroe gas plant from one customer primarily from compression and processing fees and from retaining a portion of the NGLs from the recycled lift gas.

- *CPP System.* We own five gathering systems in east Texas, totaling 64 miles. Combined average throughput on these systems was approximately 15,000 MMBtu/d for the year ended December 31, 2004.

- *Alabama Pipeline System.* The Alabama system consists of a series of three gathering and transmission systems totaling approximately 128 miles that gather gas from the traditional sandstone reservoirs on the west side of the system and coalbed methane wells on the east side of the system. Average throughput on the Alabama system was approximately 13,000 MMBtu/d for the year ended December 31, 2004.

- *Other Systems.* We own several small gathering systems, 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 Aurora Centana system in Louisiana. 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 21,000 MMBtu/d for the year ended December 31, 2004. In addition to these systems, we own various smaller gathering and transmission systems located in Texas, New Mexico and Louisiana.

- *Producer Services.* We are currently party to numerous transactions with approximately 41 independent producers under which we purchase and resell volumes of gas that do not move through our gathering, processing or transmission assets. This activity occurs on more than 20 interstate and intrastate pipelines with the majority being on Gulf Coast pipelines. Profits from these transactions were $2.3 million and $1.9 million for the years ending December 31, 2004 and 2003, respectively.

In addition to the business activity described above, we offer end users and producers the ability to hedge their purchase or sale price, provided they purchase from us or sell to us the same physical volumes of natural gas. This risk management tool enables our customers to reduce pricing volatility associated with the purchase and sale of natural gas. When we agree to hedge a price for a customer, we do so by simultaneously executing and offsetting physical 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 23% and 28% of our gross margin in 2004 and 2003, respectively. Our treating business has grown from 52 plants in operation at December 31, 2003 to 74 plants in operation at December 31, 2004.

As of December 31, 2004, we owned 90 treating plants, 60 of which were operated by our personnel, 14 of which were operated by producers, and 16 of which were held in inventory. We entered the treating business in 1998 with the acquisition of WRA Gas Services and we now have 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. 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.

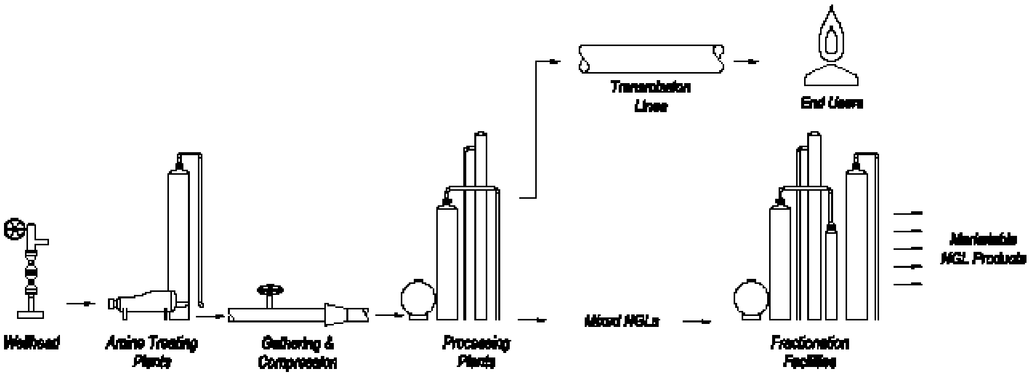
We also own an undivided 12.4% interest in the Seminole gas processing plant, which is located in Gaines County, Texas, which we account for as part of our Treating Division. The Seminole plant has dedicated long-term reserves from the Seminole San Andres unit, to which it also supplies carbon dioxide under a long-term arrangement. Revenues at the plant are derived from a fee it charges producers, primarily those at the Seminole San Andres unit, for each Mcf of carbon dioxide returned to the producer for reinjection. The fees currently average approximately $0.57 for each Mcf of carbon dioxide returned. The plant also receives 50% of the NGLs produced by the plant.

Our treating growth strategy is based on the belief that if gas prices remain high it will encourage drilling deeper gas formations. We believe the gas recovered from these formations is more likely to be high in carbon dioxide, a contaminant that generally needs to be removed before introduction into transportation pipelines. When completing a well, producers place a high value on immediate equipment availability, as they can more quickly begin to realize cash flow from a completed well. We believe our track record of reliability, current availability of equipment, and our strategy of sourcing new equipment gives us a significant advantage in competing for new treating business.

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.

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.

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 and markets. 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 geographic location of facilities in relation to production or markets, and on the reputation, efficiency and reliability of the gatherer and the pricing arrangements offered by the gatherer. Many of our competitors have substantially greater capital resources and control substantially greater supplies of natural gas. Our competition will likely differ in different geographic areas.

Our gas treating operations face competition from manufacturers of new treating plants and from a small number of regional operators that provide plants and operations similar to ours. We also face competition from vendors of used equipment that occasionally operate plants for producers.

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 evaluate well and reservoir data furnished by producers to determine the availability of natural gas supply for the systems and/or obtain a minimum volume commitment from the producer that results in a rate of return on our investment. Based on these facts, 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, 2004, we had one customer that individually accounted for more than 10% of consolidated revenues. During the year ended December 31, 2004, Kinder Morgan Tejas accounted for 10.2% 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. We do not own any interstate natural gas pipelines, so the Federal Energy Regulatory Commission ("FERC") does not directly regulate any of our operations. However, FERC's regulation influences certain aspects of our business and the market for our products. In general, FERC has authority over natural gas companies that provide natural gas pipeline transportation services in interstate commerce and its authority to regulate those services includes:

- the certification and construction of new facilities;
- the extension or abandonment of services and facilities;
- the maintenance of accounts and records;
- the acquisition and disposition of facilities;
- maximum rates payable for certain services;
- the initiation and discontinuation of services; and
- various other matters.

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. Pending before the FERC is a proposal to abandon a 500 mile section of the Transco interstate system, which if approved, would allow us to acquire that system as a FERC-deregulated asset and put it into intrastate service.

Intrastate Pipeline Regulation. Our intrastate natural gas pipeline operations generally are not subject to rate 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 and the Louisiana Department of Natural Resources Office of Conservation. However, to the extent that our intrastate pipeline systems transport 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 ("NGA"). Section 311 regulates, 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. Once set, 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.

We own a private line in New Mexico that is used to serve one customer, of which approximately one mile is regulated by the New Mexico Public Regulation Commission. Similarly, 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. The Arkoma gathering system in Oklahoma is regulated by the Oklahoma Corporation Commission. Similarly, gathering systems we own in Alabama are subject to regulation by the Alabama State Oil and Gas Board. Our LIG intrastate system is regulated by the Louisiana Department of Natural Resources Office of Conservation.

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 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. Many of the producing states have adopted some form of complaint based regulation that generally allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering access and rate discrimination. 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 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. Similar costs are likely upon any future acquisition of 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 acquired two assets from Duke Energy Field Services, L.P. ("DEFS") in June 2003 that have environmental contamination. These two assets were 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 had been identified at levels that exceeded 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 and sale agreement, DEFS retained the liability for cleanup of both the Conroe and Cadeville sites. Moreover, DEFS has entered into an agreement with a third-party company pursuant to which the remediation costs associated with the Conroe site have been assumed by this third-party company that specializes in remediation work. In addition, effective September 1, 2004, we sold our Cadeville assets, including the compressor station and gathering system, subject to the retained DEFS indemnity, to a third party. Therefore, we do not expect to incur any material environmental liability associated with the Conroe or Cadeville sites.

We acquired LIG Pipeline Company, and its subsidiaries, on April 1, 2004 from AEP. Contamination from historical operations was identified during due diligence at a number of sites owned by the acquired companies. AEP has indemnified us for these identified sites. Moreover, AEP has entered into an agreement with a third-party company pursuant to which the remediation costs associated with these sites have been assumed by this third-party company that specializes in remediation work. We do not expect to incur any material liability with these sites. In addition, we have disclosed possible Clean Air Act monitoring deficiencies we have discovered to the Louisiana Department of Environmental Quality and we are working with the department to correct these deficiencies and to address modifications to facilities to bring them into compliance. We do not expect to incur any material environmental liability associated with these issues.

Air Emissions. Our operations are, and our 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 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. In addition, the TRRC regulates our pipelines in Texas under its own pipeline integrity management rules. The Texas rule includes certain transmission and gathering lines based upon pipeline diameter and operating pressures. 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 65,000 square feet of space at our executive offices in Dallas, Texas under a lease expiring in March 2010.

Employees

As of December 31, 2004, we had approximately 325 full-time employees. Approximately 147 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 we own in fee.

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

Item 3. *Legal Proceedings*

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 our 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.

In May 2003, four landowner groups filed suit against us in the 267th Judicial District Court in Victoria County, Texas seeking damages related to the expiration of an easement for a segment of one of our pipelines located in Victoria County, Texas. In 1963, the original owners of the land granted an easement for a term of 35 years, and the prior owner of the pipeline failed to renew the easement. We filed a condemnation counterclaim in the district court suit and we filed, in a separate action in the county court, a condemnation suit seeking to condemn a 1.38 mile long easement across the land. Pursuant to condemnation procedures under the Texas Property Code, three special commissioners were appointed to hold a hearing to determine the amount of the landowner’s damages.

In August 2004, a hearing was held and the special commissioners awarded damages to the four current landowner groups in the amount of $877,500. We have timely objected to the award of the special commissioners and the condemnation case will now be tried in the county court on May 9, 2005. The damages award by the special commissioners will have no effect and cannot be introduced as evidence in the county court. The county court will determine the amount that we will pay the current landowners for an easement across their land and will determine whether or not and to what extent the current landowner groups are entitled to recover any damages for the time period that there was not an easement for the pipeline on their land. Under the Texas Property Code, in order to maintain possession of and continued use of the pipeline until the matter has been resolved in the county court, we were required to post bonds and cash, each totaling the amount of $877,500, which is the amount of the special commissioners award. We are not able to predict the ultimate outcome of this matter.

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, 2004.

PART II

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

Our common units 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 $10.00 per common unit. On February 25, 2005, the market price for the common units was $35.45 per unit and there were approximately 6,886 record holders and beneficial owners (held in street name) of our common units and one record holder of our subordinated units. There is no established public trading market for our 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(a)		
	High	**Low**	**Cash Distribution Paid Per Unit(a)(b)**
2004:			
Quarter Ended December 31	$ 33.00	$ 29.91	$ 0.45
Quarter Ended September 30	31.65	26.42	0.43
Quarter Ended June 30	29.72	24.38	0.42
Quarter Ended March 31	28.03	20.38	0.40
2003:			
Quarter Ended December 31	$ 21.79	$ 19.28	$ 0.375
Quarter Ended September 30	19.90	16.63	0.35
Quarter Ended June 30	17.20	12.18	0.275
Quarter Ended March 31	12.25	10.74	0.288(c)
2002:			
Quarter ended December 31	$ 10.88	$ 9.73	$ 0.00

(a) Unit prices and cash distributions per unit have been adjusted for the two-for-one unit split on March 29, 2004.

(b) For each quarter, an identical cash distribution was paid on all outstanding subordinated units.

(c) Reflects minimum quarterly distribution of $0.25 for the quarter ended March 31, 2004 and the pro rata portion of the $0.25 minimum quarterly distribution, covering the period for December 17, 2002 closing of our 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 $0.25 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 13 percent, 23 percent and 48 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 — 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 $0.25 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

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basis of accounting was established effective May 1, 2000 to give effect to the Yorktown transaction. In addition, our summary historical financial and operating data include the results of operations of the Arkoma system beginning in September 2000, the Gulf Coast system beginning in September 2000, the Corpus Christi system, the Gregory gathering system and the Gregory processing plant, beginning in May 2001, the Vanderbilt system beginning in December 2002, the Mississippi pipeline system and Seminole processing plant beginning in June 2003, and the LIG assets beginning in April 2004.

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, 2004	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, 200
	(Dollars in thousands, except per unit amounts)					
Statement of Operations Data:						
Revenues:						
Midstream	$ 1,948,021	$ 989,697	$ 437,432	$ 362,673	$ 88,008	$ 3,591
Treating	30,755	23,966	14,817	24,353	17,392	5,947
Total revenues	1,978,776	1,013,663	452,249	387,026	105,400	9,538
Operating costs and expenses:						
Midstream purchased gas	1,861,204	946,412	414,244	344,755	83,672	2,746
Treating purchased gas	5,274	7,568	5,767	18,078	14,876	4,731
Operating expenses	38,141	17,692	11,409	7,761	1,796	544
General and administrative(2)	20,064	6,844	7,513	5,583	2,010	810
Stock based compensation	1,001	5,345	41	—	—	8,802
Impairments	—	—	4,175	2,873	—	—
(Profit) loss on energy trading contracts	(2,507)	(1,905)	(1,657)	3,714	(1,253)	(638)
Gain on sale of property	(12)	—	—	—	—	—
Depreciation and amortization	23,034	13,268	7,745	6,101	2,261	522
Total operating costs and expenses	1,946,199	995,224	449,237	388,865	103,362	17,517
Operating income (loss)	32,577	18,439	3,012	(1,839)	2,038	(7,979)
Other income (expense):						
Interest expense, net	(9,220)	(3,392)	(2,717)	(2,253)	(530)	(79)
Other income (expense)	798	179	49	174	115	381
Total other income (expense)	(8,422)	(3,213)	(2,668)	(2,079)	(415)	302
Income before minority interest and taxes	24,155	15,226	344	(3,918)	1,623	(7,677)
Minority interest	(289)	—	—	—	—	—
Federal income taxes	(162)	—	—	—	—	—
Net income (loss)	$ 23,704	$ 15,226	$ 344	$ (3,918)	$ 1,623	$ (7,677)
Net income (loss) per limited partner unit-basic(3)	$ 0.98	$ 0.89	$ 0.02	N/A	N/A	N/A
Net income (loss) per limited partner unit-diluted(3)	$ 0.95	$ 0.88	$ 0.02	N/A	N/A	N/A
Distributions per limited partner unit(4)	$ 1.70	$ 1.25	$ 0.028	N/A	N/A	N/A
Balance Sheet Data:						
Working capital surplus (deficit)	$ (34,724)	$ (4,572)	$ (10,330)	$ (2,254)	$ 5,861	$ (4,005)
Property and equipment, net	324,730	203,909	109,948	84,951	37,242	10,540
Total assets	586,771	366,050	233,185	168,376	201,268	45,051
Long-term debt	148,700	60,750	22,550	60,000	22,000	7,000
Partners' equity	144,050	154,610	88,158	41,155	40,354	3,608
Cash Flow Data:						
Net cash flow provided by (used in):						
Operating activities	$ 48,103	$ 46,460	$ (5,672)	$ (10,244)	$ 7,741	$ 7,380
Investing activities	(124,371)	(110,289)	(33,240)	(52,535)	(25,643)	(2,849)
Financing activities	81,899	62,687	39,868	44,476	36,557	198

	Crosstex Energy, L.P.					Crosstex Energy Services, Ltd. (1)
	Year Ended December 31, 2004	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, 200
	(Dollars in thousands, except per unit amounts)					
Other Financial Data:						
Midstream gross margin	$ 86,817	$ 43,285	$ 23,188	$ 17,918	$ 4,336	$ 845
Treating gross margin	25,481	16,398	9,050	6,275	2,516	1,216
Total gross margin(5)	$ 112,298	$ 59,683	$ 32,238	$ 24,193	$ 6,852	$ 2,061
Operating Data:						
Pipeline throughput (MMBtu/d)	1,289,000	626,000	392,000	313,000	104,000	23,000
Natural gas processed (MMBtu/d)	425,000	132,000	86,000	61,000	16,000	31,000
Producer Services (MMBtu/d)	210,000	259,000	230,000	—	—	—

(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 was entitled to reimbursement from us for allocated general and administrative expenses was limited to $6.0 million. Such limitation did 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 $0.02 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) 2004 distributions include fourth quarter 2004 distributions of $0.45 per unit paid in February 2005, 2003 distributions include fourth quarter of 2003 distributions of $0.375 per unit paid in February 2004, and 2002 distributions include fourth quarter of 2002 distributions of $0.028 per unit paid in February 2003.

(5) Gross margin is defined as revenue, including treating fee revenues, less related cost of purchased gas.

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. ("CEI") 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 Gulf Coast of the United States. 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, 2004, 77% of our gross margin was generated in the Midstream division, with the balance in the Treating division. We focus on gross margin to manage our business because our business is generally to purchase and resell gas for a margin, or to gather, process, transport, market or treat gas for a fee. 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, 2004, we have invested over $300 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:

- purchasing and reselling or 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 41 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 53% and 55% of the operating income in our Treating division for the years ended December 31, 2004 and 2003, respectively;
- a fixed fee for operating the plant for a certain period, which accounted for approximately 43% and 38% of the operating income in our Treating division for the years ended December 31, 2004 and 2003, respectively; or
- a fee arrangement in which the producer operates the plant, which accounted for approximately 4% and 7% of the operating income in our Treating division for the years ended December 31, 2004 and 2003, respectively.

Operating expenses are costs directly associated with the operations of a particular asset. Among the most significant of these costs are those associated with direct labor and supervision and associated transportation and communication costs, property insurance, ad valorem taxes, repair and maintenance expenses, measurement and utilities. These costs are normally fairly stable across broad volume ranges, and therefore, do not normally decrease or increase significantly in the short term with decreases or increases in the volume of gas moved through the asset.

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 limitation 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 limitation 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 elected to cash out the options or the election to cash out the options lapsed. Crosstex Energy, Inc. was responsible for paying the intrinsic value of the options for the holders who elected 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, we ceased applying variable accounting for the remaining modified options. We recognized total compensation expense of approximately $5.0 million related to these modified options, which has been recorded by us 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 since January, 2002 are the acquisitions of Vanderbilt system, the DEFS assets, and LIG.

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 Duke Energy Field Services assets, or 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, and enabled us to enter the business of carbon dioxide separation.

In April 2004 we acquired LIG Pipeline Company and its subsidiaries (collectively, “LIG”) from a subsidiary of American Electric Power for $73.7 million in cash. The principal assets acquired consist of approximately 2,000 miles of gas gathering and transmission systems located in 32 parishes extending from northwest and north-central Louisiana through the center of the state to the south and southeast Louisiana and five processing plants, three of which are currently idle, that straddle the pipeline in three locations and have a total processing capability of 663,000 MMbtu/d. The system has a throughput capacity of 900,000 MMbtu/d and average throughput at the time of our acquisition was approximately 560,000 MMbtu/d. Customers include power plants, municipal gas systems, and industrial markets located principally in the industrial corridor between New Orleans and Baton Rouge. The LIG system is connected to several interconnected pipelines and the Jefferson Island Storage facility providing access to additional system supply. We financed the LIG acquisition through borrowings under our bank credit facility.

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 can 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 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, 2004.

	Year Ended December 31, 2004			
	Gas Purchased		Gas Sold	
Asset or Business	Fixed Amount to Index	Percentage of Index	Fixed Amount to Index	Percentage of Index
	(In thousands of MMBtus)			
Gulf Coast system	22.4	2.7	25.1	—
CCNG transmission system	75.9	5.2	81.1	—
Gregory gathering system(1)	46.9	1.8	35.4	—
Vanderbilt system(1)	20.2	13.0	30.0	—
Conroe system(1)	0.5	0.6	0.8	—
Arkoma gathering system	3.5	3.4	6.9	—
Mississippi system	28.2	0.4	28.6	—
LIG system	96.4	5.2	101.6	—
Producer services(2)	76.4	0.4	76.8	—

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

(2) These volumes are not reflected in revenues or purchased gas cost, but are presented net as a component of profit (loss) on energy trading 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 $1.6 million on an annual basis (before consideration of the hedges discussed below). As of December 31, 2004, we have hedged approximately 58% 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
First quarter of 2005	180,000	$ 6.074
Second quarter of 2005	180,000	$ 6.074
Third quarter of 2005	120,000	$ 5.851
Fourth quarter of 2005	120,000	$ 5.851

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

Our processing plants at Plaquemine and Gibson have a variety of processing contract structures. In general, we buy gas under keep-whole arrangements in which we bear the risk of processing, percentage-of-proceeds arrangements in which we receive a percentage of the value of the liquids recovered, and “theoretical” processing arrangements in which the settlement with the producer is based on an assumed processing result. Because we have the ability to bypass certain volumes when processing is uneconomic, we can limit our exposure to adverse processing margins. During periods when processing margins are favorable, we can substantially increase the volumes we are processing, as was the case in the fourth quarter of 2004.

For the year ended December 31, 2004, we purchased a small amount (approximately 4%) 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. The remaining approximately 96% of the natural gas volumes on our Gregory system were purchased 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.

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 $0.57 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. During 2004, our share of NGLs totaled 5,891,248 gallons at an average price of $0.72 per gallon.

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.

	Years Ended December 31,		
	2004	2003	2002
		(dollars in millions)	
Midstream revenues	$ 1,948.0	$ 989.7	$ 437.4
Midstream purchased gas	1,861.2	946.4	414.2
Midstream gross margin	86.8	43.3	23.2
Treating revenues	30.8	24.0	14.8
Treating purchased gas	5.3	7.6	5.8
Treating gross margin	25.5	16.4	9.0
Total gross margin	$ 112.3	$ 59.7	$ 32.2
Midstream Volumes (MMBtu/d):			
Gathering and transportation	1,289,000	626,000	392,000
Processing	425,000	132,000	86,000
Producer services	210,000	259,000	230,000
Treating Plants in Operation at Year-end	74	52	35

Year Ended December 31, 2004 Compared to Year Ended December 31, 2003

Gross Margin. Midstream gross margin was $86.8 million for the year ended December 31, 2004 compared to $43.3 million for the year ended December 31, 2003, an increase of $43.5 million, or 101%. This increase was primarily due to the acquisitions of the LIG assets on April 1, 2004 and DEFS assets on June 30, 2003, which added an incremental $27.7 million and $7.9 million, respectively, to midstream gross margin. The volume growth of 956,000 MMBtu/d, or 97%, in gathering, transportation, and processing was primarily due to the acquired LIG and DEFS assets. Also contributing to improved margins were higher processing margins and volumes from existing gas processing operations, which increased margins by $3.4 million from 2004 to 2003.

Treating gross margin was $25.5 million for the year ended December 31, 2004 compared to $16.4 million in the year ended December 31, 2003, an increase of $9.1 million, or 55%. Of this increase, $4.5 million was due to the Seminole Plant, one of the assets acquired from DEFS, being owned for a full year. The Seminole Plant has increased from 20% of operating income in 2003 to 34% of operating income during 2004, as the Seminole Plant was only owned for the last six months of 2003. Also contributing to the significant growth was the placement of an additional 37 plants in service since December 31, 2003, which was offset in part by 15 plant retirements. The net plant additions of 22 generated $4.1 million in additional gross margin.

Operating Expenses. Operating expenses were $38.0 million for the year ended December 31, 2004 compared to $17.7 million for the year ended December 31, 2003, an increase of $20.3 million, or 115%. Increases of $3.5 million and $9.5 million were associated with the acquisition of the DEFS and LIG assets, respectively. General operations expense (expenses not directly related to specific assets) was $6.0 for 2004 compared to $1.7 million for 2003. The majority of the $4.3 million increase was related to higher technical services support required by the newly-acquired assets and additional expenditures related to our pipeline integrity program. The growth in treating plants in service increased operating expenses by $1.2 million.

General and Administrative Expenses. General and administrative expenses were $20.1 million for the year ended December 31, 2004 compared to $6.8 million for the year ended December 31, 2003, an increase of $13.3 million, or 196%. The increase was due in part to the general and administrative expense limit set by our partnership agreement for 2003, which resulted in general and administrative expenses in excess of specified levels being borne by the general partner. Had the limitation not been in place, general and administrative expenses would have been $10.2 million, resulting in an actual increase from 2003 to 2004 of $9.9 million, or 97%. A significant part of the increased expenses was $5.0 million of additional staffing related costs. The staff additions required to manage and optimize our LIG and DEFS acquisitions account for the majority of the change, although a number of leadership and strategic positions were added that will allow us to absorb future growth more efficiently. Consistent with staffing for future growth, an additional $1.0 million in consulting costs were made to upgrade our systems, providing a more scalable infrastructure. Sarbanes Oxley compliance costs are an additional $1.1 million for 2004 compared to zero in 2003. A $0.6 million increase due to unsuccessful transaction costs was a result of, among other things, the size of the acquisitions pursued. Other expenses, including audit and tax fees, office rent, K-1 preparation fees and travel expenses, account for $1.1 million of the increase.

Stock-Based Compensation. Stock-based compensation expense decreased from $5.3 million for the year ended December 31, 2003 to $1.0 million for the year ended December 31, 2004. During 2003, certain outstanding CEI options were accounted for using variable accounting due to a “cash-out” modification offered for such options and stock compensation expense was recognized because the estimated fair value of the options increased during 2003. The “cash-out” modification offered during 2003 that caused the variable accounting treatment expired on December 31, 2003 and, effective January 1, 2004, the remaining CEI options are accounted for as fixed options. Stock-based compensation recognized in 2004 represents the amortization of costs associated with awards under long-term incentive plans, including restricted units and option grants with exercise prices below market prices on the grant date.

(Profit) Loss on Energy Trading Activities. The profit on energy trading activities was $2.5 million for the year ended December 31, 2004 compared to $1.9 million for the year ended December 31, 2003. Included in these amounts are realized margins on delivered volumes in the producer services “off-system” gas marketing operations of $2.3 million and $2.2 million for the years ended December 30, 2004 and 2003, respectively.

Gain on Sale of Property. During 2004, we sold two small gathering systems and recognized a net gain on sale of $12,000.

Depreciation and Amortization. Depreciation and amortization expenses were $23.0 million for the year ended December 31, 2004 compared to $13.3 million for the year ended December 31, 2003, an increase of $9.8 million, or 74%. The increase related to the DEFS assets was $2.6 million and the increase related to the LIG assets was $3.3 million. New treating plants placed in service resulted in an increase of $2.2 million. The remaining $1.7 million increase in depreciation and amortization is a result of expansion projects and other new assets, including the expansion of the Gregory Plant and the consolidation of Denton County assets.

Interest Expense. Interest expense was $9.2 million for the year ended December 31, 2004 compared to $3.4 million for the year ended December 31, 2003, an increase of $5.8 million, or 172%. The increase relates primarily to an increase in average debt outstanding. Average interest rates also increased from 2003 to 2004 (weighted average rate of 6.1% in 2004 compared to 5.4% in 2003).

Other Income. Other income was $798,000 for the year ended December 31, 2004 compared to $179,000 for the year ended December 31, 2003. Other income in 2004 includes the write-off of $167,000 related to an environmental liability accrued in connection with the June 2003 acquisition of properties from DEFS which was in excess of amounts spent to resolve the environmental matters identified at the time of acquisition. In addition, other income in 2004 includes $277,000 related to a reimbursement for a construction project in excess of our costs for such projects.

Minority Interest in Subsidiary. We recognized $289,000 of minority interest expense for the year ended December 31, 2004 related to the third-party joint venture partner’s 50% share of the Crosstex DC Gathering, J.V. We began consolidating this joint venture on January 1, 2004 upon adoption of FASB Interpretation No. 46R, *Consolidation of Variable Interest Entities, an interpretation of ARB No. 51.*

Income Tax Expense. Income tax expense was $162,000 for the year ended December 31, 2004 compared to $0 for the year ended December 31, 2003, an increase of $162,000. The tax expense relates to the Partnership’s wholly-owned taxable corporate structure formed in conjunction with the acquisition of the LIG Pipeline Company and its subsidiaries in April 2004.

Net Income. Net income for the year ended December 31, 2004 was $23.7 million compared to $15.2 million for the year ended December 31, 2003, an increase of $8.5 million. As detailed in each net income component above, the significant contribution of recent acquisitions impact on both the Midstream and Treating business segments, in addition to a large number of plant additions in the Treating division were the primary drivers. Also, higher liquid processing margins and higher product prices positively impacted both Midstream and Treating results.

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

Gross Margin. Midstream gross margin was $43.4 million for the year ended December 31, 2003 compared to $23.2 million for the year ended December 31, 2002, an increase of $20.2 million, or 87%. The largest increase in gross margin was due to the acquisition of assets from DEFS on June 30, 2003. These assets added gross margin of $6.0 million. The Corpus Christi 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 six 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 $16.4 million for the year ended December 31, 2003 compared to $9.0 million in the same period in 2002, an increase of $7.4 million, or 82%. The Seminole asset acquired from DEFS accounted for $3.4 million of the increase. The remaining 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 DEFS 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 limitation 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 DEFS acquisition and associated with being a public entity.

Impairments. We had no impairment expense in 2003 compared to a $4.2 million charge in 2002 related primarily to contract valuations recorded as intangible assets as part of the Partnership’s formation.

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

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

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

Net Income (Loss). Net income for the year ended December 31, 2003 was $15.2 million compared to $0.3 million for the year ended December 31, 2002, an increase of $14.9 million. This was generally the result of the increase in gross margin of $27.5 million from 2002 to 2003, offset by increases in ongoing cash costs for operating expenses and interest expense as discussed above. Non-cash charges for depreciation and amortization expenses and stock based compensation also increased.

Critical Accounting Policies

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

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 which is recognized net in profit from energy trading activities. 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 $48.1 million for the year ended December 31, 2004 compared to cash provided by operations of $46.5 million for the year ended December 31, 2003. Income before non-cash income and expenses was $47.5 million in 2004 and $33.6 million in 2003. Changes in working capital provided $0.6 million in cash flows from operating activities in 2004 and used $12.8 million in cash flows from operating activities in 2003. 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, 2004 compared to year ended December 31, 2003." Changes in working capital are primarily due to the timing of collections at the end of the quarterly periods. We collect and pay large receivables and payables at the end of each calendar month and the timing of these payments and receipts may vary by a day or two between month-end periods, causing these fluctuations.

Net cash used in investing activities was $124.4 million and $110.3 million for the year ended December 31, 2004 and 2003, respectively. Net cash used in investing activities during 2004 related to the LIG acquisition ($73.7 million) and the purchase of the outside partner interests in Crosstex Pipeline Partners ($5.1 million) as well as internal growth projects. The primary internal growth projects during 2004 were buying, refurbishing and installing treating plants ($24.5 million). Net cash used in investing activities during 2003 related to the DEFS acquisition ($68.1 million) together with internal growth projects consisting of 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).

Net cash provided by (used in) financing activities was $81.9 million and $62.7 million for the years ended December 31, 2004 and 2003, respectively. Financing activities for 2004 relate principally to the funding of the LIG and CPP acquisitions and the funding of internal growth projects discussed above from bank borrowings and borrowings under the senior secured notes. Financing activities in 2003 relate principally to the funding of the DEFS assets acquisition and internal growth projects discussed above from bank borrowings and proceeds from the sale of common units discussed below. Financing activities also included an increase in drafts payable of $28.2 million for the year ended December 31, 2004 and a decrease in drafts payable of $17.1 million for the year ended December 31, 2003. 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.

Working Capital Deficit. We had a working capital deficit of $34.7 million as of December 31, 2004, primarily due to drafts payable of $38.7 million as of the same date. As discussed under “Cash Flows” above, in order to reduce our interest costs we do not borrow money to fund outstanding checks until they are presented to our bank. We borrow money under our $100.0 million acquisition credit facility to fund checks as they are presented. As of December 31, 2004, we had $67.0 million of available borrowings under this facility.

Off-Balance Sheet Arrangements. We had no off-balance sheet arrangements as of December 31, 2004 and 2003.

September 2003 Sale of Common Units. In September 2003, we completed a public offering of 3,450,000 common units at a public offering price of $17.985 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, and expenditures made in support of that growth.

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 $0.45 per quarter and to fund a portion of our anticipated capital expenditures through December 31, 2005. Total capital expenditures are budgeted to be approximately $42 million in 2005, although we anticipate significantly higher capital expenditures due to pending projects such as the North Texas Pipeline project. We expect to fund the remaining capital expenditures from the proceeds of borrowings under the revolving credit facility discussed below, and for future issuance of units. 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.

Total Contractual Cash Obligations. A summary of our total contractual cash obligations as of December 31, 2004, is as follows:

	Payments Due by Period						
	Total	2005	2006	2007	2008	2009	Thereafter
				(In millions)			
Long-Term Debt	$ 148.7	$ 0.1	$ 39.5	$ 10.0	$ 9.4	$ 9.4	$ 80.3
Capital Lease Obligations	—	—	—	—	—	—	—
Operating Leases	8.7	1.8	1.5	1.4	1.3	1.2	1.5
Unconditional Purchase Obligations	—	—	—	—	—	—	—
Other Long-Term Obligations	—	—	—	—	—	—	—
Total Contractual Obligations	$ 157.4	$ 1.9	$ 41.0	$ 11.4	$ 10.7	$ 10.6	$ 81.8

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

Description of Indebtedness

As of December 31, 2004 and 2003, long-term debt consisted of the following (dollars in thousands):

	December 31, 2004	December 31, 2003
Acquisition credit facility, interest based on Prime and/or LIBOR plus an applicable margin, interest rates (per the facility) at December 31, 2004 and 2003 were 4.99% and 2.92%, respectively	$ 33,000	$ 20,000
Senior secured notes, weighted average interest rate of 6.95% and 6.93% at December 31, 2004 and 2003, respectively	115,000	40,000
Note payable to Florida Gas Transmission Company	700	750
	148,700	60,750
Less current portion	(50)	(50)
Debt classified as long-term	$ $148,650	$ $60,700

Bank Credit Facility. In April 2004 we amended our $120 million senior secured credit facility with Union Bank of California, N.A. (as a lender and as administrative agent) and other lenders, to increase the credit facility to $200 million, consisting of the following two facilities:

- a $100.0 million senior secured revolving acquisition facility; and
- a $100.0 million senior secured revolving working capital and letter of credit facility.

The acquisition facility was used for the LIG acquisition in April 2004 and will be used to finance future acquisition and development of gas gathering, treating and processing facilities, as well as general partnership purposes. At December 31, 2004, $33.0 million was outstanding under the acquisition facility, leaving approximately $67.0 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, 2004 we had $65.7 million of letters of credit issued under the $100.0 million working capital and letter of credit facility, leaving approximately $34.3 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 $50.0 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 rank *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 option at the administrative agent's reference rate plus 0.25% to 1.00% or LIBOR plus 1.75% to 2.50%. The applicable margin varies quarterly based on our leverage ratio. The fees charged for letters of credit range from 1.50% to 1.75% per annum, plus a fronting fee of 0.125% per annum. We 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 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 3.5 to 1, pro forma for any asset acquisitions; and
- 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.

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, we entered into a master shelf agreement with an institutional lender pursuant to which we 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, we 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. In June 2004, the master shelf agreement was amended, increasing the amount issuable under the agreement from

$50.0 million to $125.0 million. In June 2004, we issued $75.0 million aggregate principal amount of senior secured notes with an interest rate of 6.96% and a maturity of ten years.

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

The notes represent our senior secured obligations 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 our obligations 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 significant subsidiaries and us.

The initial $40.0 million of senior secured notes are redeemable, at our 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 $75.0 million senior secured notes issued in June 2004 provide for a call premium of 103.5% of par beginning June 2007 through 2013 at rates declining from 103.5% to 100.0%. The notes are not callable prior to June 2007.

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

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

The Partnership was in compliance with all debt covenants at December 31, 2004 and 2003 and expects to be in compliance for the next twelve months.

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

Credit Risk

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

Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the years ended December 31, 2002, 2003 or 2004. 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 and Other Contingencies

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."

In March 2005 we received a claim of approximately $700,000 for damages and lost profits from one of our customers. The claim relates to an October 2004 incident in which natural gas liquids, which can drop out of the gas stream in pipelines and tend to clog the lines, were being removed from one of our lines pursuant to normal operating procedures. Some of the liquids may have inadvertently been diverted to the customer's facilities. We have no basis at this time to evaluate the merits of the customer's claim or to reasonably estimate any potential liability we may have.

Recent Accounting Pronouncements

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 December 2004, the FASB issued SFAS No. 123 (Revised 2004), *Share-Based Payment,* which requires that compensation related to all stock-based awards, including stock options, be recognized in the financial statements. This pronouncement replaces SFAS No. 123, *Accounting for Stock-Based Compensation,* and supersedes APB Opinion No. 25, *Accounting for Stock Issued to Employees* and will be effective beginning July 1, 2005. We have previously recorded stock compensation pursuant to the intrinsic value method under APB No. 25, whereby no compensation was recognized for most stock option awards. We expect that stock option grants will continue to be a significant part of employee compensation, and therefore, SFAS No. 123R will have a significant impact on our financial statements. Although we have not determined the impact of SFAS 123R, the pro forma effect of recording compensation for all stock awards at fair value utilizing the Black-Scholes method for the years ended December 31, 2004, 2003 and 2002 resulted in a decrease in our net income of $227,000, $249,000 and $287,000, respectively.

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. In January 2004, the Partnership adopted FIN No. 46R and began consolidating its joint venture interest in the Crosstex DC Gathering, J.V. (CDC), previously accounted for using the equity method of accounting. The consolidated carrying amount for the joint venture is based on the historical costs of the assets, liabilities and non-controlling interests of the joint venture since its formation in January 2003 which approximates the carrying amount of the assets, liabilities and non-controlling interests in the consolidated financial statements as if FIN No. 46R had been effective upon inception of the joint venture.

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 54% 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;
- Bryan Lawrence, the Chairman of the Board of Directors of Crosstex Energy GP, LLC, is a senior manager at Yorktown Partners LLC, the manager of the Yorktown group of investment partnerships ("Yorktown"), which until January 2005, in the aggregate owned more than 50% of the common shares of Crosstex Energy, Inc. Yorktown has been reducing its ownership in Crosstex Energy, Inc. through a process of distribution of shares to its investors. Such continued distributions could have the effect of allowing another group to take control of Crosstex Energy, Inc., which might impact the nature of the our future operations;
- 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, operational and environmental risks, some of which may not be covered by insurance;
- 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; and
- our unit prices and our ability to raise capital may be negatively impacted if interest rates rise in the future.

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. Our primary market risk is the risk related to changes in the prices of natural gas and natural gas liquids (NGL's). In addition, we are also exposed to the risk of changes in interest rates on our floating rate debt.

Commodity price risk. Approximately 8% of the natural gas we purchase for resale is purchased on a percentage of the relevant natural gas price index, as opposed to a fixed discount to that price. As a result of purchasing the gas at a percentage of the index price, our margins are higher during periods of higher natural gas prices and lower during periods of lower natural gas prices. We have hedged approximately 58% of our exposure to gas price fluctuations through the end of 2005.

Another price risk we face is the risk of mismatching volumes of gas bought or sold on a monthly price versus volumes bought or sold on a daily price. We enter each month with a balanced book of gas bought and sold on the same basis. However, it is normal to experience fluctuations in the volumes of gas bought or sold under either basis, which leaves us with short or long positions that must be covered. We use financial swaps to mitigate the exposure at the time it is created to maintain a balanced position.

We have commodity price risk associated with our processed volumes of natural gas. We currently process gas under four main types of contractual arrangements:

1. Keep-whole contracts: Under this type of contract, we pay the producer for the full amount of inlet gas to the plant, and we make a margin based on the difference between the value of liquids recovered from the processed natural gas as compared to the value of the natural gas volumes lost ("shrink") in processing. Our margins from these contracts are high during periods of high liquids prices relative to natural gas prices, and can be negative during periods of high natural gas prices relative to liquids prices. We control our risk on our current keep-whole contracts primarily through our ability to bypass processing when it is not profitable for us.

2. Percent of proceeds contracts: Under these contracts, we receive a fee in the form of a percentage of the liquids recovered, and the producer bears all the cost of the natural gas shrink. Therefore, our margins from these contracts are greater during periods of high liquids prices. Our margins from processing cannot become negative under percent of proceeds contracts, but decline during periods of low NGL prices.

3. Theoretical processing contracts: Under these contracts, we stipulate with the producer the assumptions under which we will assume processing economics for settlement purposes, independent of actual processing results or whether the stream was actually processed. These contracts tend to have an inverse result to the keep-whole contracts, with better margins as processing economics worsen.

4. Fee based contracts: Under these contracts we have no commodity price exposure, and are paid a fixed fee per unit of volume that is treated or conditioned.

Our primary commodity risk management objective is to reduce volatility in our cash flows. We maintain a Risk Management Committee, including members of senior management, which oversees all hedging activity. We enter into hedges for natural gas and natural gas liquids 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.

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

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.

Set forth below is the summarized notional amount and terms of all instruments held for price risk management purposes at December 31, 2004 (all quantities are expressed in British Thermal Units). The remaining term of the contracts extend no later than October 2007, with no single contract longer than 6 months. Our counterparties to derivative contracts include BP Corporation, UBS Energy and Total Gas & Power. Changes in the fair value of our derivatives related to third-party producers and customers 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 and the ineffective portion is recorded in earnings. Fair value hedges and their underlying physical are marked to market and the changes in their fair value are recorded in earnings as profit or loss on energy trading contracts.

December 31, 2004				
Transaction Type	**Total Volume**	**Pricing Terms**	**Remaining Term of Contracts**	**Fair Value**
				(In thousands)
Cash Flow Hedge:				
Natural gas swaps cash flow hedge	2,088,000	Fixed prices ranging from $5.66 to $7.07 settling against	January 2005-December 2005	$ 69
Natural gas swaps cash flow hedge	(3,438,000)	various Inside FERC Index prices	January 2005-December 2005	$ (164)
Total natural gas swaps cash flow hedge				$ (95)
Natural gas liquids (“NGLS”) swaps cash flow hedge	(1,633,716)	Fixed prices ranging from $0.5142 to $1.115 settling against Mt. Belvieu Average of daily postings (non-TET)	January 2005-March 2005	$ 122
Total NGL swaps cash flow hedge				$ 122
Mark to Market Derivatives:				
Swing swaps	3,209,690	Prices ranging from Inside FERC Index less $0.525 to Inside FERC Index plus $0.0075 settling against	January 2005- March 2005	$ (31)
Swing swaps	(1,214,921)	various Inside FERC Index prices	January 2005-March 2005	(7)
Total swing swaps				$ (38)
Physical offset to swing swap transactions	1,214,921	Prices ranging from Inside FERC Index less $0.01 to Inside FERC Index settling against various	January 2005- March 2005	—
Physical offset to swing swap transactions	(3,209,690)	Inside FERC Index prices	January 2005-March 2005	(23)
Total physical offset to swing swaps				$ (23)
Third party on-system financial swaps	3,460,000	Fixed prices ranging from $4.83 to $7.225 settling against various	January 2005- October 2007	$ (1,254)
Third party on-system financial swaps	(720,000)	Inside FERC Index prices	January 2005- October 2007	439
Total third party on-system financial swaps				$ (815)

Transaction Type	Total Volume	Pricing Terms	Remaining Term of Contracts	Fair Value (In thousands)
		December 31, 2004		
Physical offset to third party on-system transactions	420,000	Fixed prices ranging from $4.675 to $6.93 settling against various	January 2005- October 2007	$ (242)
Physical offset to third party on-system transactions	(3,160,000)	Inside FERC Index prices	January 2005- October 2007	$ 1,264
Total physical offset to marketing trading transactions swaps				$ 1,022
Marketing trading financial swaps	(450,000)	Fixed prices of $5.945 settling against Inside FERC Index Texas Eastern E. TX prices	January 2005- March 2005	$ 6
Total marketing trading financial swaps				$ 6
Physical offset to marketing trading transactions	450,000	Fixed prices of $5.855 settling against Inside FERC Index Texas Eastern E. TX prices	January 2005- March 2005	$ 19
Total physical offset to marketing trading transactions swaps				$ 19
Natural gas swaps	(85,000)	Fixed prices ranging from $9.335 to $9.38 settling against various Inside FERC Index prices	February 2005	$ 774
Total natural gas swaps				$ 774

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.

Item 8. *Financial Statements and Supplementary Data*

The Report of Independent Registered Public Accounting Firm Consolidated Financial Statements and supplementary financial data required by this Item are set forth on pages F-1 through F-38 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, 2004 to provide reasonable assurance that information required to be disclosed in our reports to 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 on forms.

There has been no change in our internal controls over financial reporting that occurred in the three months ended December 31, 2004 that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

Internal Control Over Financial Reporting

See “Management’s Report on Internal Control Over Financial Reporting” on page F-2.

Item 9B. ***Other Information***

None.

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.

Unitholders do not directly or indirectly participate in our management or operation. Our general partner owes a fiduciary duty to the unitholders, 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 serve until their successors are duly appointed or elected.

Name	Age	Position with Crosstex Energy GP, LLC
Barry E. Davis	43	President, Chief Executive Officer and Director
James R. Wales	51	Executive Vice President — Southern Division
A. Chris Aulds	43	Executive Vice President — Eastern Division
Jack M. Lafield	54	Executive Vice President — Corporate Development
William W. Davis	51	Executive Vice President and Chief Financial Officer
Robert S. Purgason	48	Senior Vice President — Treating Division
Michael P. Scott	50	Senior Vice President — Technical Services
Rhys J. Best**	56	Director and Member of the Conflicts Committee*
Frank M. Burke**	65	Director and Member of the Audit Committee*
C. Roland Haden**	64	Director and Member of the Audit Committee
Bryan H. Lawrence	62	Chairman of the Board
Sheldon B. Lubar**	75	Director and Member of the Compensation Committee*
Robert F. Murchison**	51	Director and Member of the Compensation Committee
Stephen A. Wells**	61	Director and Member of the Audit Committee

* Denotes chairman of committee.

** Denotes independent 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 also serves as a director of Crosstex Energy, Inc. 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 — Eastern Division 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 over 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.

Robert S. Purgason, Senior Vice President — Treating Division, joined Crosstex in October 2004 to lead the Treating Division. Prior to joining Crosstex, Mr. Purgason spent 19 years with Williams Companies in various senior business development and operational roles. He was most recently Vice President of the Gulf Coast Region Midstream Business Unit. Mr. Purgason began his career at Perry Gas Companies in Odessa working in all facets of the treating business. Mr. Purgason received a B.S. degree in Chemical Engineering with honors from the University of Oklahoma.

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.

Rhys J. Best joined Crosstex Energy GP, LLC as a director in June 2004. Mr. Best is Chairman and Chief Executive Officer of Lone Star Technologies, Inc., a holding company whose principal operating companies produce and market premium casing, tubing, line pipe and couplings for the oil and gas industry; specialty tubing for the industrial, automotive, and power generation industries; and flat rolled steel and other tubular products and services. Mr. Best has held the position of Chief Executive Officer since June 1998 and he assumed the additional responsibilities of Chairman in January 1999. He began his career at Lone Star as the President and Chief Executive Officer of Lone Star Steel Company, a position he held for eight years before becoming President and Chief Operating Officer of the parent company in 1997. Mr. Best graduated from the University of North Texas with a Bachelor of Business degree and later earned a Masters of Business Administration Degree at Southern Methodist 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., Kaneb Pipe Line Partners, L.P., Xanser Corporation and Kaneb Services LLC. Mr. Burke has also served as a director of Crosstex Energy, Inc. since January 2004. 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 in December 2002. 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 has also served as a director of Crosstex Energy, Inc. since January 2005. 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 us as a director upon the completion of our initial public offering in December 2002. 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 certain non-public companies in the energy industry in which Yorktown partnerships hold equity interests including PetroSantander Inc., Savoy Energy, L.P., Athanor Resources Inc., Camden Resources, Inc., ESI Energy Services Inc., Ellora Energy Inc., and Dernick Resources Inc. Mr. Lawrence also serves as a director of Crosstex Energy, Inc. 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 in December 2002. 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, Grant Prideco, Inc., an energy services company, since 2000, and Weatherford International, Inc., an energy services company, since 1995. Mr. Lubar has also served as a director of Crosstex Energy, Inc. since January 2004. 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 in December 2002. 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, rail car repair and the fund of funds management business, since 1978. Mr. Murchison has also served as a director of Crosstex Energy, Inc. since January 2004. 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 in December 2002. 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 has also served as a director of Crosstex Energy, Inc. since January 2005. Mr. Wells holds a bachelor's degree in accounting from Abilene Christian University.

"Independent" Directors

Messrs. Best, 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, 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, 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.

Mr. Best serves as the chair of the 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. In order to have a duly constituted Conflicts Committee, at least one more director who satisfies such membership requirements must be appointed to serve on such committee. 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 unitholders.

The Compensation Committee, 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 of our employees, officers, and directors, with regard to Partnership-related activities. The Code of Business Conduct and Ethics incorporates guidelines designed to deter wrongdoing and to promote honest and ethical conduct and compliance with applicable laws and regulations. It also incorporates expectations of our employees that enable us to provide accurate and timely disclosure in our filings with the SEC 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 the Code 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 our general partner’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

Based upon our records, except as hereinafter set forth, we believe that during 2004 all of such reporting persons complied with the Section 16(a) filing requirements applicable to them. On August 20, 2004, Form 4s were filed on behalf of Frank M. Burke, Robert F. Murchison, Sheldon B. Lubar and C. Roland Haden with respect to option and restricted stock grants that such individuals received on September 1, 2003. On November 22, 2004, a Form 4A was filed on behalf of Rhys J. Best correcting information contained in filings on November 15, 2004 and November 17, 2004. On December 22, 2004, Form 4s were filed on behalf of Leslie J. Wylie and Susan J. McAden with respect to option grants received on February 5, 2004.

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 limitation 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 four other most highly compensated executive officers in 2002, 2003 and 2004. 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, prior to mid-December 2002, its predecessor.

Summary Compensation Table

		Annual Compensation			Long-Term Compensation Awards (3)			
Name and Principal Position	Year	Salary (1) ($)	Bonus (2) ($)	Other Annual Compensation ($)	Restricted Stock Awards ($)	Restricted Unit Awards ($)	Units Underlying Options (#)	All Other Compensation ($)
Barry E. Davis	2004	$ 267,483	$ 247,500	—	$ 291,000	—	—	—
President and Chief	2003	210,000	177,000	—	—	285,670	—	—
Executive Officer	2002	201,500	100,750	—	—	—	60,000	—
James R. Wales	2004	$ 202,731	$ 126,000	—	$ 363,750	—	—	—
Executive Vice President —	2003	180,000	108,000	—	—	181,790	—	—
Southern Division	2002	171,064	59,872	—	—	—	40,000	—
A. Chris Aulds	2004	$ 200,500	$ 126,000	—	$ 363,750	—	—	—
Executive Vice President —	2003	180,000	108,000	—	—	181,790	—	—
Eastern Division	2002	171,064	59,872	—	—	—	40,000	—
Jack M. Lafield	2004	$ 199,436	$ 126,000	—	$ 436,500	—	—	—
Executive Vice President —	2003	170,000	108,000	—	—	181,790	—	—
Corporate Development	2002	160,875	56,306	—	—	—	35,000	—
William W. Davis	2004	$ 199,436	$ 126,000	—	$ 436,500	—	—	—
Executive Vice President	2003	170,000	108,000	—	—	181,790	—	—
and Chief Financial Officer	2002	160,875	93,306	—	—	—	35,000	—

(1) Reflects the aggregate salary paid by the registrant and its predecessor for fiscal 2002, 2003 and 2004. 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, and W. Davis was $8,396, $7,128, $7,128, $6,703, and $6,703, 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 and from Crosstex Energy, Inc. in 2004. For a description of awards granted to date under the Long-Term Incentive Plan. See "— Long-Term Incentive Plan."

Employment Agreements

The executive officers, including Barry E. Davis, James R. Wales, A. Chris Aulds, Jack M. Lafield and William W. Davis, have entered into employment agreements with the Partnership. 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 a term of one year that 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 $275,000, $210,000, $210,000, $210,000 and $210,000 for Barry E. Davis, James R. Wales, A. Chris Aulds, Jack M. Lafield and William W. Davis, respectively, as of February 28, 2005.

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, as amended, permits the grant of awards covering an aggregate of 1,400,000 common units, which may be awarded in the form of restricted units or 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 the approval requirements of 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 it 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 or of our general partner.

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, under current policy, 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 or our general partner 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, 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 unitholders.

Option Grants

No options were granted to the named officers in 2004.

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 2004, 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, 2004.

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

Name	Shares Acquired on Exercise (#)	Value Realized ($)	Number of Securities Underlying Unexercised Options at 12/31/04 (#) Exercisable	Unexercisable	Value of Unexercised In-the-Money Options at 12/31/04 ($) Exercisable	Unexercisable
Barry E. Davis	—	—	40,000	20,000	$ 1,319,200	$ 659,600
James R. Wales	—	—	26,667	13,333	879,478	439,722
A. Chris Aulds	—	—	26,667	13,333	879,478	439,722
Jack M. Lafield	—	—	23,333	11,667	769,522	384,778
William W. Davis	—	—	23,333	11,667	769,522	384,778

The closing price for the common units was $32.98 at December 31, 2004.

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 regularly scheduled 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 $1,500 for each Audit Committee meeting. Each committee chairman receives $2,500 annually, except the Audit Committee chairman who receives $7,500 annually. Directors are also reimbursed for related out-of-pocket expenses. 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. During 2004 Mr. Best received a one-time grant of 10,000 options at an exercise price of $25.75 (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 have served as members of the Compensation Committee of the board of directors of Crosstex Energy GP, LLC since the completion of our initial public offering.

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

The following table shows the beneficial ownership of units of Crosstex Energy, L.P. as of February 25, 2005, 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.	666,000	7.4%	9,334,000	100.0%	53.9%
Barry E. Davis(2)(3)	40,000	*	—	—	—
James R. Wales(2)(3)	26,667	*	—	—	—
A. Chris Aulds(2)(3)	26,667	*	—	—	—
Jack M. Lafield(2)(3)	23,333	*	—	—	—
William W. Davis(2)(3)	23,333	*	—	—	—
Rhys J. Best	5,000	—	—	—	—
Frank Burke	12,667	*	—	—	*
C. Roland Haden(4)	18,333	*	—	—	*
Bryan H. Lawrence(5)	—	—	—	—	—
Sheldon B. Lubar(6)	17,740	*	—	—	—
Stephen A. Wells	23,333	*	—	—	*
Robert F. Murchison(7)	67,740	*	—	—	*
All directors and executive officers as a group (15 persons)(3)	305,064	3.4%	—	—	*

* Less than 1%.

(1) The address of each person listed above is 2501 Cedar Springs, Dallas, Texas 75201, except for Crosstex Holdings L.P., which is 1209 Orange Street, Wilmington, Delaware 19801, 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 and William W. Davis 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 40,000 units for Mr. Barry E. Davis, 26,667 units for Mr. Wales, 26,667 units for Mr. Aulds, 23,333 units for Mr. Lafield, 23,333 units for Mr. William W. Davis, 6,667 units for Mr. Burke, 6,667 units for Mr. Haden, 12,866 units for Mr. Lubar, 6,667 units for Mr. Wells, 8,459 units for Mr. Murchison and 197,993 units for all directors and executive officers as a group.

(4) 5,000 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) 50,000 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. Mr. Murchison

and Murchison Capital Partners, L.P. hold ownership interests in Crosstex Energy, Inc. as indicated in the following table.

The following table shows the beneficial ownership of Crosstex Energy, Inc. as of February 25, 2005, held by:

- each person who beneficially owns 5% or more of the stock 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)	Shares of Common Stock	Percent
Yorktown Energy Partners IV, L.P.(2)	4,654,198	37.94%
Yorktown Energy Partners V, L.P.(2)	1,193,371	9.73%
Lubar Nominees(3)	697,498	5.69%
Barry E. Davis(4)	638,916	5.19%
James R. Wales(4)	306,722	2.48%
A. Chris Aulds(4)	383,268	3.11%
Jack M. Lafield(4)	72,440	*
William W. Davis(4)	74,936	*
Frank M. Burke	10,000	«
C. Roland Haden	2,500	«
Bryan H. Lawrence(5)	95,043	*
Sheldon B. Lubar(3)	699,316	5.70%
Stephen A. Wells	—	—
Robert F. Murchison(6)	44,318	*
All directors and executive officers as a group (15 persons)(4)	2,390,109	18.89%

* 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, 46,504 shares for Mr. Lafield, 50,000 shares for Mr. William W. Davis and 325,140 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.

(6) 42,500 shares 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.

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	1,400,000(1)	$ 15.58(2)	234,582(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, as amended, provides for issuance of a total of 1.4 million common unit options and restricted units.

(2) The strike prices for outstanding options under the plan as of December 31, 2004 range from $10.00 to $30.00 per unit.

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 limitation 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.

Our general partner owns a 2% general partner interest in us and all of our 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 $0.25 per unit, 23% of the amounts we distribute in excess of $0.3125 per unit and 48% of amounts we distribute in excess of $0.375 per unit.

Relationship with Crosstex Energy, Inc.

General. Crosstex Energy, Inc. indirectly owns 666,000 common units and 9,334,000 subordinated units representing an aggregate 54.2% 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 54.2% 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, 2004, we purchased natural gas from Camden Resources, Inc. in the amount of approximately $38.4 million and received approximately $2.4 in treating fees from Camden Resources, Inc.

Crosstex Pipeline Partners, LP. We indirectly owned general and limited partner interests in Crosstex Pipeline Partners, L.P. (CPP) that represented a 28% economic interest. Effective December 31, 2004 we acquired all of the other limited and general partner interests (approximately 72%) of this partnership for $5.1 million. Purchased assets include current assets of $1.8 million offset by current liabilities assumed of $1.6 million and property, plant and equipment of $5.0 million. This acquisition makes us the sole limited partner of CPP and Crosstex Pipeline, LLC (a 100% owned subsidiary of ours) the sole general partner.

We entered into various transactions with CPP, and we believe that the terms of these transactions were comparable to those that we could have negotiated with unrelated third parties. During the year ended December 31, 2004, we: (1) purchased natural gas from CPP in the amount of approximately $11.6 million and paid CPP approximately $51,000 for transportation of natural gas, (2) received a management fee from CPP in the amount of approximately $125,000 and (3) received approximately $159,000 in distributions from CPP.

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.

Item 14. ***Principal Accounting 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, 2005.

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, 2004 and December 31, 2003, review of our internal control procedures for the fiscal year ended December 31, 2004, 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 $937,271 and $411,500, 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, 2004 and December 31, 2003 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, 2004 and December 31, 2003 were $100,075 and $103,725, 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, 2004 and December 31, 2003.

Audit Committee Approval of Audit and Non-Audit Services

All non-audit services and any services that exceed the annual limits set forth in the policy must be pre-approved by the Audit Committee. In 2005, the Audit Committee has not pre-approved the use of KPMG for any non-audit related services. 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 and Financial Statement Schedules***

(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 F-38.

(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	—	Second Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of March 29, 2004 (incorporated by reference to Exhibit 3.2 to our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004).
3.3	—	Amendment No. 1 to Second Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of April 1, 2004 (incorporated by reference to Exhibit 3.3 to our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004).
3.4	—	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).
3.5	—	Second Amended and Restated Agreement of Limited Partnership of Crosstex Energy Services, L.P., dated as of April 1, 2004 (incorporated by reference to Exhibit 3.5 to our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004).
3.6	—	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).
3.7	—	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).
3.8	—	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).
3.9	—	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).

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Number		Description
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 (incorporated by reference to Exhibit 10.3 to our Annual Report on Form 10-K for the year ended December 31, 2003).
10.4	—	Third Amendment to Second Amended and Restated Credit Agreement, dated as of April 1, 2004, by and 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 Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004).
10.5	—	Fourth Amendment to Second Amended and Restated Credit Agreement, dated as of June 18, 2004, by and 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 Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004).
10.6	—	$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).
10.7	—	Letter Amendment No. 1 to Master Shelf Agreement, dated as of April 1, 2004, among Crosstex Energy Services, L.P., Prudential Investment Management, Inc., The Prudential Insurance Company of America and Pruco Life Insurance Company (incorporated by reference to Exhibit 10.2 to our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004).
10.8	—	Letter Amendment No. 2 to Master Shelf Agreement, dated as of June 18, 2004, among Crosstex Energy Services, L.P., Prudential Investment Management, Inc., The Prudential Insurance Company of America and Pruco Life Insurance Company (incorporated by reference to Exhibit 10.2 to our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004).
10.9	—	Purchase and Sale Agreement, dated as of February 13, 2004, by and between AEP Energy Services Investments, Inc. and Crosstex Energy, L.P. (incorporated by reference to Exhibit 2.1 to our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004).
10.10	—	First Amendment to Purchase and Sale Agreement, dated as of February 13, 2004, by and between AEP Energy Services Investments, Inc. and Crosstex Energy, L.P. (incorporated by reference to Exhibit 2.2 to our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004).
10.11	—	Second Amendment to Purchase and Sale Agreement, dated as of April 1, 2004, by and between AEP Energy Services Investments, Inc. and Crosstex Louisiana Energy, L.P. (incorporated by reference to Exhibit 2.3 or our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004).
10.12	—	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).
10.13	—	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).
10.14†	—	Crosstex Energy GP, LLC Long-Term Incentive Plan, dated July 12, 2002 (incorporated by reference to Exhibit 10.4 to Annual Report on Form 10-K for the year ended December 31, 2002).
10.15	—	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).
10.16†	—	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).

Number		Description
10.17	—	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).
10.18	—	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).
10.19	—	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).
10.20	—	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.

† As required by Item 14(a)(3), this exhibit is identified as a compensatory benefit plan or arrangement

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 14th day of March 2005.

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 14, 2005
/s/ Rhys J. Best Rhys J. Best	Director	March 14, 2005
/s/ Frank M. Burke Frank M. Burke	Director	March 14, 2005
/s/ C. Roland Haden C. Roland Haden	Director	March 14, 2005
/s/ Bryan H. Lawrence Bryan H. Lawrence	Chairman of the Board	March 14, 2005
Sheldon B. Lubar	Director	
/s/ Robert F. Murchison Robert F. Murchison	Director	March 14, 2005
/s/ Stephen A. Wells Stephen A. Wells	Director	March 14, 2005
/s/ William W. Davis William W. Davis	Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	March 14, 2005

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**MANAGEMENT'S REPORT ON
INTERNAL CONTROL OVER FINANCIAL REPORTING**

Management of Crosstex Energy GP, LLC is responsible for establishing and maintaining adequate internal control over financial reporting and for the assessment of the effectiveness of internal control over financial reporting for Crosstex Energy, L.P. (the "Partnership"). As defined by the Securities and Exchange Commission (Rule 13a-15(f) under the Exchange Act of 1934, as amended), internal control over financial reporting is a process designed by, or under the supervision of Crosstex Energy GP, LLC's principal executive and principal financial officers and effected by its Board of Directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements in accordance with U.S. generally accepted accounting principles.

The Partnership's internal control over financial reporting is supported by written policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the Partnership's transactions and dispositions of the Partnership's assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of the consolidated financial statements in accordance with U.S. generally accepted accounting principles, and that receipts and expenditures of the Partnership are being made only in accordance with authorization of the Crosstex Energy GP, LLC's management and directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Partnership's assets that could have a material effect on the consolidated financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In connection with the preparation of the Partnership's annual consolidated financial statements, management has undertaken an assessment of the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO Framework). Management's assessment included an evaluation of the design of the Partnership's internal control over financial reporting and testing of the operational effectiveness of those controls.

Based on this assessment, management has concluded that as of December 31, 2004, the Partnership's internal control over financial reporting was effective to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

The Partnership acquired the remaining outside limited and general partner interests of Crosstex Pipeline Partners (CPP) during 2004, and management excluded from its assessment of the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2004, CPP's internal control over financial reporting associated with total assets of $5,203,000 and total revenues of $0 included in the consolidated financial statements of Crosstex Energy, L.P. and subsidiaries as of and for the year ended December 31, 2004.

KPMG LLP, the independent registered public accounting firm that audited the Partnership's consolidated financial statements included in this report, has issued an attestation report on management's assessment of internal control over financial reporting, a copy of which appears on the next page of this Annual Report on Form 10-K.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Partners of
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, 2004 and 2003, 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, 2004. In connection with our audits of the consolidated financial statements, we also have audited the accompanying financial statement schedule. These consolidated financial statements and financial statement schedule are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Crosstex Energy, L.P. and subsidiaries as of December 31, 2004 and 2003, and the results of their operations, comprehensive income, and their cash flows for each of the years in the three-year period ended December 31, 2004, in conformity with U.S. generally accepted accounting principles. 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.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Crosstex Energy, L.P.'s internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 14, 2005, expressed an unqualified opinion on management's assessment of, and the effective operations of, internal control over financial reporting.

KPMG LLP

Dallas, Texas
March 14, 2005

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Partners of
Crosstex Energy, L.P.:

We have audited management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that Crosstex Energy, L.P. (a Delaware limited partnership) maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Partnership's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Partnership's internal control over financial reporting based on our audit.

We conduced our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that Crosstex Energy, L.P. maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Also, in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

The Partnership acquired the remaining outside limited and general partner interests of Crosstex Pipeline Partners (CPP) during 2004, and management excluded from its assessment of the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2004, CPP's internal control over financial reporting associated with total assets of $5,203,000 and total revenues of $0, included in the consolidated financial statements of Crosstex Energy, L.P. and subsidiaries as of and for the year ended December 31, 2004. Our audit of internal control over financial reporting of the Partnership also excluded an evaluation of the internal control over financial reporting of CPP.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Crosstex Energy, L.P. and subsidiaries as of December 31, 2004 and 2003, 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, 2004, and our report dated March 14, 2005 expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP

Dallas, Texas
March 14, 2005

CROSSTEX ENERGY, L.P.

Consolidated Balance Sheets
December 31, 2004 and 2003

	2004	2003
	(In thousands except unit data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 5,797	$ 166
Accounts receivable:		
Trade	19,453	10,238
Accrued revenues	211,700	124,517
Imbalances	573	447
Related party	486	1,618
Note receivable	570	535
Other	1,481	2,588
Fair value of derivative assets	3,025	4,080
Prepaid expenses, natural gas storage, and other	5,077	1,979
Total current assets	248,162	146,168
Property and equipment:		
Transmission assets	181,679	99,650
Gathering systems	35,624	27,990
Gas plants	125,559	87,140
Other property and equipment	8,952	3,743
Construction in process	18,006	9,863
Total property and equipment	369,820	228,386
Accumulated depreciation	(45,090)	(24,477)
Total property and equipment, net	324,730	203,909
Fair value of derivative assets	166	—
Intangible assets, net	5,155	5,366
Goodwill, net	4,873	4,873
Investment in limited partnerships	—	2,560
Other assets, net	3,685	3,174
Total assets	$ 586,771	$ 366,050
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Drafts payable	$ 38,667	$ 10,446
Accounts payable	3,996	6,325
Accrued gas purchases	213,037	119,900
Accounts payable — related party	—	448
Accrued imbalances payable	2,046	212
Fair value of derivative liabilities	2,085	2,487
Current portion of long-term debt	50	50
Other current liabilities	23,005	10,872
Total current liabilities	282,886	150,740
Long-term debt	148,650	60,700
Deferred tax liability	8,005	—
Minority interest	3,046	—
Fair value of derivative liabilities	134	—
Partners' equity:		
Common unit holders (8,755,000 and 8,716,000 units issued and outstanding at December 31, 2004 and 2003, respectively)	111,960	116,780
Subordinated unit holders (9,334,000 units issued and outstanding at December 31, 2004 and 2003)	28,002	33,593
General partner interest (2% interest with 369,000 and 368,000 equivalent units outstanding at December 31, 2004 and 2003, respectively)	4,078	2,854
Accumulated other comprehensive income	10	1,383
Total partners' equity	144,050	154,610
Total liabilities and partners' equity	$ 586,771	$ 366,050

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Operations

	Years Ended December 31, 2004	2003	2002
	(In thousands except per unit data)		
Revenues:			
Midstream	$ 1,948,021	$ 989,697	$ 437,432
Treating	30,755	23,966	14,817
Total revenues	1,978,776	1,013,663	452,249
Operating costs and expenses:			
Midstream purchased gas	1,861,204	946,412	414,244
Treating purchased gas	5,274	7,568	5,767
Operating expenses	38,141	17,692	11,409
General and administrative	20,064	6,844	7,513
Stock-based compensation	1,001	5,345	41
Impairments	—	—	4,175
(Profit) loss on energy trading activities	(2,507)	(1,905)	(1,657)
Gain on sale of property	(12)	—	—
Depreciation and amortization	23,034	13,268	7,745
Total operating costs and expenses	1,946,199	995,224	449,237
Operating income	32,577	18,439	3,012
Other income (expense):			
Interest expense, net of interest income	(9,220)	(3,392)	(2,717)
Other income	798	179	49
Total other income (expense)	(8,422)	(3,213)	(2,668)
Income before minority interest and taxes	24,155	15,226	344
Minority interest in subsidiary	(289)	—	—
Income tax provision	(162)	—	—
Net income	$ 23,704	$ 15,226	$ 344
Allocation of 2002 net income:			
Net income for the period from January 1, 2002 to December 16, 2002	—	—	$ 24
Net income for the period from December 17, 2002 to December 31, 2002	—	—	320
Net income	—	—	$ 344
General partner interest in net income for the period from December 17, 2002 to December 31, 2002 and for the years ended December 31, 2003 and 2004	$ 5,913	$ 1,240	$ 6
Limited partners' interest in net income for the period from December 17, 2002 to December 31, 2002 and for the years ended December 31, 2003 and 2004	$ 17,791	$ 13,986	$ 314
Net income per limited partners' unit:			
Basic	$ 0.98	$ 0.89	$ 0.02
Diluted	$ 0.95	$ 0.88	$ 0.02
Weighted average limited partners' units outstanding			
Basic	18,081	15,752	14,600
Diluted	18,633	15,960	14,620

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Changes in Partners' Equity
Years ended December 31, 2004, 2003 and 2002

	Crosstex Energy Services, Ltd. Partners' equity	Crosstex Energy, L.P. Common units	Subordinated units	General partner interest	Accumulated other comprehensive income	Total
		(In thousands)				
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	24	—	—	—	—	24
Distributions	(2,500)	—	—	—	—	(2,500)
Transfer of equity in accordance with initial public offering	(48,824)	17,258	30,589	977	—	—
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	—	57,561	30,790	983	(1,176)	88,158
Net proceeds from issuance of common units	—	57,336	—	—	—	57,336
Capital contributions	—	—	—	1,266	—	1,266
Stock-based compensation	—	2,121	3,117	107	—	5,345
Distributions	—	(6,016)	(8,522)	(742)	—	(15,280)
Net income	—	5,778	8,208	1,240	—	15,226
Hedging gains or losses reclassified to earnings	—	—	—	—	4,267	4,267
Adjustment in fair value of derivatives	—	—	—	—	(1,708)	(1,708)
Balance, December 31, 2003	—	116,780	33,593	2,854	1,383	154,610
Proceeds from exercise of common unit options	—	425	—	—	—	425
Stock-based compensation	—	367	391	243	—	1,001
Distributions	—	(14,217)	(15,168)	(4,932)	—	(34,317)
Net income	—	8,605	9,186	5,913	—	23,704
Hedging gains or losses reclassified to earnings	—	—	—	—	(4,015)	(4,015)
Adjustment in fair value of derivatives	—	—	—	—	2,642	2,642
Balance, December 31, 2004	$ —	$ 111,960	$ 28,002	$ 4,078	$ 10	$ 144,050

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Comprehensive Income
December 31, 2004, 2003 and 2002

	2004	2003	2002
		(In thousands)	
Net income	$ 23,704	$ 15,226	$ 344
Hedging gains or losses reclassified to earnings	(4,015)	4,020	(178)
Adjustment in fair value of derivatives	2,642	(1,461)	(1,140)
Comprehensive income	$ 22,331	$ 17,785	$ (974)

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Cash Flows

	Years Ended December 31,		
	2004	2003	2002
		(In thousands)	
Cash flows from operating activities:			
Net income	$ 23,704	$ 15,226	$ 344
Adjustments to reconcile net income to net cash provided by (used in) operating activities:			
Depreciation and amortization	23,034	13,268	7,745
Impairments	—	—	4,175
Gain on sale of property	(12)	—	—
Minority interest in earnings	289	—	—
Deferred tax benefit	(190)	—	—
Income (loss) on investment in affiliated partnerships	(304)	(208)	41
Non-cash stock-based compensation	1,001	5,345	41
Changes in assets and liabilities, net of acquisition effects:			
Accounts receivable and accrued revenue	(47,604)	(33,143)	(47,291)
Prepaid expenses, natural gas storage and other	(2,682)	(754)	178
Accounts payable, accrued gas purchases, and other accrued liabilities	50,676	41,084	31,204
Fair value of derivatives	(752)	(208)	(4,669)
Other	943	5,850	2,560
Net cash provided by (used in) operating activities	48,103	46,460	(5,672)
Cash flows from investing activities:			
Additions to property and equipment	(45,984)	(39,003)	(14,545)
Acquisitions and asset purchases	(78,895)	(68,124)	(18,785)
Proceeds from sales of property	611	—	—
Additions to other non-current assets	(115)	(1,027)	—
Distributions from (investments in) affiliated partnerships	12	(2,135)	90
Net cash used in investing activities	(124,371)	(110,289)	(33,240)
Cash flows from financing activities:			
Proceeds from borrowings	491,500	320,100	384,050
Payments on borrowings	(403,550)	(281,900)	(421,500)
Increase (decrease) in drafts payable	28,221	(17,100)	25,628
Debt refinancing costs	(1,370)	(1,735)	—
Contributions from minority interest party	990	—	—
Distribution to partners	(34,317)	(15,280)	(2,500)
Proceeds from exercise of unit options	425	—	—
Net proceeds from public equity offerings	—	57,336	40,190
Contribution from partners	—	1,266	14,000
Net cash provided by financing activities	81,899	62,687	39,868
Net increase (decrease) in cash and cash equivalents	5,631	(1,142)	956
Cash and cash equivalents, beginning of period	166	1,308	352
Cash and cash equivalents, end of period	$ 5,797	$ 166	$ 1,308
Cash paid for interest	$ 7,556	$ 3,388	$ 2,558
Cash paid for income taxes	$ 380	—	—
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, 2004 and 2003

(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) 666,000 common units and (iii) 9,334,000 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, 2004, Yorktown Energy Partners IV, L.P. and Yorktown Energy Partners V, L.P. (collectively, Yorktown) owned 53.4% of CEI and CES management and directors owned 17.9% of CEI.

(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 Partnership proportionately consolidates its undivided 12.4% interest in a carbon dioxide processing plant acquired in June 2004. In January 2004, the Partnership adopted FASB Interpretation No. 46R, Consolidation of Variable Interest Entities ("FIN No. 46R") and began consolidating its joint venture interest in Crosstex DC Gathering, J.V. as discussed more fully in Note 4. 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 three to seven 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	15-25 years
Gathering systems	7-15 years
Gas treating, gas processing and carbon dioxide plants	15 years
Other property and equipment	3-7 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. An impairment of approximately $4,175,000 associated with certain assets and the related intangible assets was recorded in the year ended December 31, 2002. The impairment recorded in 2002 relates primarily to customer relationships recorded as intangible assets as part of CES' 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, the Partnership must estimate the undiscounted cash flows attributable to the asset. The Partnership's 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.

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements — (Continued)

(d) Amortization of Intangibles

Until January 1, 2002, goodwill was amortized on a straight-line basis over 15 years. The Partnership discontinued the amortization of goodwill effective January 1, 2002 with the adoption of SFAS No. 142. As of December 31, 2004, accumulated amortization of goodwill was $508,000.

The Partnership has approximately $4.9 million of goodwill at December 31, 2004, 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 2004, 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 range from three to seven years. Such amortization was approximately $1,211,000, $896,000 and $454,000 for the years ended December 31, 2004, 2003 and 2002, respectively. See impairment of intangibles discussed in note 2(c). As of December 31, 2004, accumulated amortization of intangible assets was $3,301,000.

The following table summarizes the Partnership's estimated aggregate amortization expense for the next five years (in thousands):

2005	$ 1,400
2006	1,400
2007	1,149
2008	1,009
2009	132
Thereafter	65
Total	$ 5,155

(e) Other Assets

Unamortized debt issuance costs totaling $2.5 million as of December 31, 2004 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, 2004 also include the noncurrent portion of the note receivable from RLAC Gathering Group, L.P., the minority interest partner in the joint venture 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 of the imbalance. These imbalances are typically settled with deliveries of natural gas. The Partnership had an imbalance payable of $2,046,000 and $212,000 at December 31, 2004 and 2003, respectively, which approximates the fair value of these imbalances. The Partnership had an imbalance receivable of $573,000 and $447,000 at December 31, 2004 and 2003, respectively, which 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.

Currently, some of the derivative financial instruments that qualify for hedge accounting are designated as cash flow hedges. The cash flow hedge 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 closes. 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.

Certain derivative financial instruments that qualify for hedge accounting are not necessarily designated as cash flow hedges. These financial instruments and their physical quantities are marked to market and recorded on the balance sheet in fair value of derivative assets or liabilities with the related earnings impact recorded in the period transactions are entered into.

In addition, certain derivative financial instruments qualify as fair value hedges. We use these instruments to hedge the value of the future sale of physical gas currently held as storage inventory. These financial instruments and the related physical quantities are marked to market and the related earnings impact is recorded in the period the transactions are entered into.

(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 net realized gains or losses on settled contracts, is reported net as profit or loss on energy trading contracts in the statements of operations.

Net 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 $2,271,000, $2,231,000 and $1,791,000 for the years ended December 31, 2004, 2003 and 2002, respectively.

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

	Years Ended December 31,		
	2004	2003	2002
Volumes purchased and sold	76,576,000	94,572,000	84,069,000

(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.

Pursuant to SFAS No. 133, the Partnership records deferred hedge gains and losses on its derivative financial instruments that qualify as cash flow hedges as other comprehensive income.

(k) Income Taxes

The Partnership is generally not subject to income taxes, except as discussed below, because its income is taxed directly to its partners. The net tax basis in the Partnership's assets and liabilities is less than the reported amounts on the financial statements by approximately $60.6 million as of December 31, 2004.

The new LIG entities the Partnership formed to acquire the stock of LIG Pipeline Company and its subsidiaries, as discussed more fully in Note 3, are treated as taxable corporations for income tax purposes. The entity structure was formed to effect the matching of the tax cost to the Partnership of a step-up in the basis of the assets to fair market value with the recognition of benefits of the step-up by the Partnership.

For the year ended December 31, 2004, the Partnership recognized a current tax expense of $352,000 on the LIG entities' net taxable income and a deferred tax benefit of $190,000. A deferred tax liability of $8,195,000 was recorded at the acquisition date. The deferred tax liability represents future taxes payable on the difference between the fair value and tax basis of the assets acquired.

The Partnership provides for income taxes using the liability method. Accordingly, deferred taxes are recorded for the differences between the tax and book basis that will reverse in future periods (in thousands).

	2004
Current tax provision (benefit)	$ 352
Deferred tax provision (benefit)	(190)
	$ 162

A reconciliation of the provision for income taxes for the taxable corporation is as follows (in thousands):

Federal income tax (benefit) as statutory rate (35%)	$ 154
State income taxes, net	8
Tax provision (benefit)	$ 162

The principal component of the Partnership's net deferred tax liability is as follows (in thousands):

Deferred income tax liabilities:	
Property, plant, equipment, and intangible assets	$ (8,005)

(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 since 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. See Note 10 for further discussion. The Partnership records reserves for uncollectible accounts on a specific identification basis since there is not a large volume of late paying customers. As of December 31, 2004, the Partnership had a $59,000 reserve for uncollectible receivables. No reserve was recorded as of December 31, 2003.

During the years ended December 31, 2004, 2003 and 2002, the Partnership had one customer which individually accounted for more than 10% of consolidated revenues. The relevant percentages for this customer were: (i) for the year ended December 31, 2004 — 10.2%; (ii) for the year ended December 31, 2003 — 20.5%; and (iii) for the year ended December 31, 2002 — 27.5%. While this customer represents a significant percentage of revenues, the loss of this customer 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, 2004, 2003 and 2002, 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 its option plan. In accordance with APB No. 25 for fixed stock and unit options, compensation is recorded to the extent the market 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 $1,001,000, $5,345,000, and $41,000 was recognized in 2004, 2003, and 2002, respectively. The portion of compensation expense for 2004 and 2003 related to operating activities was $199,000 and $2,122,000, respectively, and the remaining expense for the 2004 and 2003 of $802,000 and $3,223,000, respectively, related to general and administrative activities.

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

	Years Ended December 31, 2004	2003	2002
Net income, as reported	$ 23,704	$ 15,226	$ 344
Add: Stock-based employee compensation expense included in reported net income	1,001	5,345	41
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards	(1,228)	(5,594)	(328)
Pro forma net income	$ 23,477	$ 14,977	$ 57

	Years Ended December 31, 2004	2003
Net income per limited partner unit, as reported:		
Basic	$ 0.98	$ 0.89
Diluted	$ 0.95	$ 0.88
Pro forma net income per limited partner unit:		
Basic	$ 0.97	$ 0.87
Diluted	$ 0.95	$ 0.86

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

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements — (Continued)

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 2004, 2003, and 2002:

	Crosstex Energy, L.P.		
	2004	**2003**	**2002**
Weighted average dividend yield	6.4%	9.8%	10%
Weighted average expected volatility	29%	24%	24%
Weighted average risk free interest rate	3.25%	2.65%	2.2%
Weighted average expected life	4.9 years	4.3 years	3 years
Contractual life	10 years	10 years	10 years
Weighted average of fair value of unit options granted	$4.00	$1.28	$0.58

	Crosstex Energy, Inc.	
	2004	**2002**
Weighted average dividend yield	5.4%	0%
Weighted average expected volatility	30%	0%
Weighted average risk free interest rate	3.26%	4.1%
Weighted average expected life	4.5 years	3 years
Contractual life	10 years	3 years
Weighted average of fair value of unit options granted	$4.76	$1.56

No Crosstex Energy, Inc. options were granted to employees, officers or directors of the Partnership 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

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 December 2004, the FASB issued SFAS No. 123 (Revised 2004), *Share-Based Payment,* which requires that compensation related to all stock-based awards, including stock options, be recognized in the financial statements. This pronouncement replaces SFAS No. 123, *Accounting for Stock-Based Compensation,* and supersedes APB Opinion No. 25, *Accounting for Stock Issued to Employees* and will be effective beginning July 1, 2005. We have previously recorded stock compensation pursuant to the intrinsic value method under APB No. 25, whereby no compensation was recognized for most stock option awards. We expect that stock option grants will continue to be a significant part of employee compensation, and therefore, SFAS No. 123R will have a significant impact on our financial statements with the prospective adoption of this accounting method in July 2005. Although we have not determined the impact of SFAS No. 123R, the pro forma effect of recording compensation for all stock awards at fair value utilizing the Black-Scholes method is disclosed in *Stock-Based Compensation* in (n) above.

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. In January 2004, the Partnership adopted FIN No. 46R and began consolidating its joint venture interest in the Crosstex DC Gathering, J.V. (CDC), previously accounted for using the equity method of accounting. The consolidated carrying amount for the joint venture is based on the historical costs of the assets, liabilities and non-controlling interests of the joint venture since its formation in January 2003 which approximates the carrying amount of the assets, liabilities and non-controlling interests in the consolidated financial statements as if FIN No. 46R had been effective upon inception of the joint venture.

(3) Significant Asset Purchases and Acquisitions

On June 6, 2002, CES acquired 70 miles of then-inactive pipeline from Florida Gas Transmission Company for $1,474,000 in cash and an $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 50% 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, which consisted 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 in 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

Intangibles relate to customer relationships and are being amortized over seven years.

In April 2004, the Partnership acquired, through its wholly-owned subsidiary Crosstex Louisiana Energy, L.P., the LIG Pipeline Company and its subsidiaries (LIG Inc., Louisiana Intrastate Gas Company, L.L.C., LIG Chemical Company, LIG Liquids Company, L.L.C. and Tuscaloosa Pipeline Company) (collectively, “LIG”) from American Electric Power (“AEP”) in a negotiated transaction for $73.7 million. LIG consists of approximately 2,000 miles of gas gathering and transmission systems located in 32 parishes extending from northwest and north-central Louisiana through the center of the state to south and southeast Louisiana. The Partnership financed the acquisition in April through borrowings under its amended bank credit facility.

We have utilized the purchase method of accounting for this acquisition with an acquisition date of April 1, 2004. The purchase price and our allocation thereof are as follows (in thousands):

Cash paid to AEP	$	70,509
Leased assets acquired		451
Direct acquisition costs		2,732
Total Purchase Price	$	73,692
Assets acquired:		
Current assets	$	45,602
Property plant & equipment		87,142
Intangible assets		1,000
Liabilities assumed:		
Current liabilities		(51,857)
Deferred tax liability		(8,195)
Total Purchase Price	$	73,692

Intangible assets relate to customer relationships and are being amortized over three years.

The purchase price allocation for the LIG acquisition has not been finalized because the Partnership is still in the process of settling pre-acquisition liabilities with AEP.

Operating results for the DEFS assets have been included in the Statements of Operations since June 30, 2003, and operating results for the LIG assets have been included in the Statements of Operations since April 1, 2004. The following unaudited pro forma results of operations assume that the DEFS acquisition and the LIG acquisition occurred on January 1, 2003 (in thousands, except per unit amounts):

	Pro Forma (Unaudited) Years Ended December 31,			
		2004		2003
Revenue	$	2,180,056	$	1,922,028
Net income	$	16,783	$	7,375
Net income per limited partner unit				
Basic	$	0.93	$	0.40
Diluted	$	0.90	$	0.39
Weighted average limited partners' units outstanding				
Basic		18,081		15,752
Diluted		18,633		15,960

(4) Investment in Limited Partnerships and Note Receivable

The Partnership owns a 50% interest in Crosstex Denton County Gathering, J.V. ("CDC"). Prior to 2004, the Partnership accounted for its investment in CDC under the equity method. Under this method, the Partnership carried its investments at cost and recorded 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 were recorded as a reduction in the Partnership's investment in the affiliated partnership. In January 2004, the Partnership began consolidating its investment in CDC pursuant to FIN No. 46R.

In connection with the formation of CDC, the Partnership agreed to loan the CDC partner up to $1.5 million for its 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 $570,000 from the CDC partner is included in current notes receivable as of December 31, 2004. The remaining balance of $1,083,000 is included in other non-current assets as of December 31, 2004.

Until December 31, 2004, the Partnership owned a 7.86% weighted average interest as the general partner in the five gathering systems of Crosstex Pipeline Partners, L.P. ("CPP") and a 20.31% interest as a limited partner in CPP. The Partnership accounted for its investment in CPP under the equity method for the years ended December 31, 2002, 2003 and 2004 because it exercised significant influence in operating decisions as a general partner in CPP.

Effective December 31, 2004, the Partnership acquired all of the outside limited and general partner interests of the CPP Partnership for $5.1 million. This acquisition makes the Partnership the sole limited partner and general partner of CPP, so the Partnership began consolidating its investment in CPP effective December 31, 2004.

We utilized the purchase method of accounting for the acquisition of the CPP partnership interests as follows (in thousands):

Cash paid	$	5,030
Direct acquisition costs		173
Total purchase price	$	5,203
Assets acquired:		
Current assets	$	1,838
Property, plant and equipment		5,013
Liabilities assumed:		
Current liabilities		(1,648)
Total purchase price	$	5,203

(5) Long-Term Debt

As of December 31, 2004 and 2003, long-term debt consisted of the following (in thousands):

		2004		2003
Acquisition credit facility, interest based on Prime or LIBOR plus an applicable margin, interest rates at December 31, 2004 and 2003 were 4.99% and 2.92%, respectively	$	33,000	$	20,000
Senior secured notes, weighted average interest rate of 6.95% and 6.93%, respectively		115,000		40,000
Note payable to Florida Gas Transmission Company		700		750
		148,700		60,750
Less current portion		(50)		(50)
Debt classified as long-term	$	148,650	$	60,700

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements — (Continued)

Credit Facility. In April 2004, the Partnership amended its $120 million senior secured credit facility with Union Bank of California (as a lender and administrative agent) and five other banks to increase the credit facility to $200 million, consisting of the following two facilities:

- a $100.0 million senior revolving acquisition facility; and
- a $100.0 million senior secured revolving working capital and letter of credit facility.

The acquisition facility was used for the LIG 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, 2004, $33.0 million was outstanding under the acquisition facility, leaving approximately $67.0 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, 2004, $65.7 million of letters of credit were issued under the working capital facility, leaving approximately $34.3 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 $50.0 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. The Partnership is required to reduce all working capital borrowings to zero for a period of at least 15 consecutive days once a year.

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 the Partnership's option at the administrative agent's reference rate plus 0.25% to 1.0% or LIBOR plus 1.75% to 2.50%. The applicable margin varies quarterly based on our leverage ratio. The fees charged for letters of credit range from 1.50% to 1.75% per annum, plus a fronting fee of 0.125% per annum. The Partnership incurs 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 the 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 the Partnership's agreement; and
- engage in transactions with affiliates.

The credit facility contains the following covenants requiring the Partnership 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; and
- 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.

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, the 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, the 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. In June 2004, the master shelf agreement was amended, increasing the amount issuable under the agreement from $50.0 million to $125.0 million. In June 2004, the Partnership issued $75.0 million aggregate principal amount of senior secured notes with an interest rate of 6.96% and a maturity of ten years.

These notes represent senior secured obligations of the 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 Partnership under the credit facility, by first priority liens on all of its material pipeline, gas gathering and processing assets, all material working capital assets and a pledge of all its equity interests in certain of its subsidiaries. The senior secured notes are guaranteed by the Partnership's subsidiaries.

The initial $40.0 million of senior secured notes are redeemable, at the 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 $75.0 million senior secured notes issued in June 2004 provide for a call premium of 103.5% of par beginning June 2007 through 2013 at rates declining from 103.5% to 100.0%. The notes are not callable prior to June 2007.

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, 2004 and 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 2004, 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 the 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 the Partnership'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 through June 2006 with a final payment of $600,000 due in June 2007. The note bears interest payable annually at LIBOR plus 1%.

Maturities. Maturities for the long-term debt as of December 31, 2004 are as follows (in thousands):

2005	$	50
2006		39,520
2007		10,012
2008		9,412
2009		9,412
Thereafter		80,294

Interest Rate Swap. 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 was subject to interest rate risk on its acquisition credit facility. The interest rate swap reduced 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 expired on November 1, 2004. The Partnership accounted for this swap as a cash flow hedge of the variable interest payments. Accordingly, unrealized gains or losses related to the swap were recorded in other comprehensive income and were 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 was 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 4,600,000 common units representing limited partner interests at a price of $10.00 per common unit. Total proceeds from the sale of the 4,600,000 units were $46.0 million, before offering costs and underwriting commissions.

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Notes to Consolidated Financial Statements — (Continued)

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 3,450,000 common units at a public offering price of $17.99 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 2,633,000 additional common units or an equivalent number of securities ranking on parity with the common units without obtaining unitholder 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 ended 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. The Partnership's senior secured credit facility prohibits the Partnership from declaring distributions to unitholders if any event of default exists or would result from the declaration of distributions. See Note (5) for a description of the bank credit facility covenants.

Under the quarterly incentive distribution provisions, generally our general partner is entitled to 13% of amounts we distribute in excess of $0.25 per unit, 23% of the amounts we distribute in excess of $0.3125 per unit and 48% of amounts we distribute in excess of $0.375 per unit. Incentive distributions totaling $5,550,000 and $954,000 were earned by our general partner for the years ended December 31, 2004 and 2003, respectively. To the extent there is sufficient available cash, the holders of common units are entitled to receive the minimum quarterly distribution of $0.25 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 paid annual per common unit distributions of $1.70, $1.288 and $0 for the years ended December 31, 2004, 2003 and 2002, respectively.

The Partnership increased its fourth quarter distribution on its common and subordinated units to $0.45 per unit which was paid on February 16, 2005.

(7) Retirement Plans

The Partnership sponsors a single employer 401(k) plan for employees who become eligible upon the date of hire. The Partnership made year end discretionary contributions to the plan of $259,000 and $198,000 for the years ended December 31, 2003 and December 31, 2002, respectively.

During 2004 the Partnership amended the plan to allow for contributions to be made at each compensation calculation period based on the annual discretionary contribution rate. Contributions to the plan for the year ended December 31, 2004 were $479,000.

(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 1,400,000 common unit options and restricted units. 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, 96,000 restricted units were issued to senior management under the long-term incentive plan with an intrinsic value of $1,247,000. In September 2003, 2,150 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 ratably over the vesting period. The Partnership recognized stock-based compensation expense of $257,000 and $197,000 related to the amortization of these restricted units in 2004 and 2003, respectively.

(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 years ended December 31, 2004, 2003 and 2002 is provided below:

	Years Ended December 31,					
	2004		2003		2002	
	Number of Units	Weighted Average Exercise Price	Number of Units	Weighted Average Exercise Price	Number of Units	Weighted Average Exercise Price
Outstanding, beginning of period	643,272	$ 10.28	350,000	$ 10.00	—	—
Granted	466,296	22.52	294,772	10.61	350,000	$ 10.00
Exercised	(39,066)	11.00	—	—	—	—
Forfeited	(26,637)	15.64	(1,500)	10.00	—	—
Outstanding, end of period	1,043,865	$ 15.58	643,272	$ 10.28	350,000	$ 10.00
Options exercisable at end of period	263,078	$ 10.36	143,334	$ 10.00	—	—
Weighted average fair value of options granted with an exercise price equal to market price at grant	116,902	$ 4.91	284,020	$ 1.16	350,000	$ 0.58
Weighted average fair value of options granted with an exercise price less than market price at grant	349,394	$ 3.70	10,752	$ 3.54	—	—

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Notes to Consolidated Financial Statements — (Continued)

The following table summarizes information about outstanding options as of December 31, 2004:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number	Weighted Average Remaining Term	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
$10.00-$11.63	572,941	8.1 Years	$ 10.03	253,796	$ 10.01
$16.50-$18.25	48,200	8.9 Years	$ 17.40	6,667	$ 18.15
$21.25-$23.90	307,679	9.1 Years	$ 21.27	2,615	$ 23.90
$25.75-$30.00	115,045	9.6 Years	$ 27.20	—	$ —
Total	1,043,865	8.6 Years	$ 15.57	263,078	$ 10.36

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 10,752 common units (in aggregate) in the Partnership in payment of their 2003 annual director fees. The options vest over a three-year period with an exercise price of $11.63 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 and Restricted Stock

CEI has one stock-based compensation plan, the Crosstex Energy, Inc. Long-Term Incentive Plan. The plan currently permits the grant of awards covering an aggregate of 1,200,000 options for common stock and restricted shares. The plan is administered by the compensation committee of the Company's board of directors.

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. Compensation costs for fixed awards with pro rata vesting are recognized on a straight-line basis over the vesting period.

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 $47,000, $5,041,000, and $41,000 was recognized in 2004, 2003, and 2002, 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. As discussed below, CEI modified certain outstanding options during 2003 which were accounted for using variable accounting.

A summary of the status of the 2000 Stock Option Plan as of December 31, 2004 and 2003, 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):

	Years Ended December 31,					
	2004		2003		2002	
	Number of Shares	Weighted Average Exercise Price	Number of Shares	Weighted Average Exercise Price	Number of Shares	Weighted Average Exercise Price
Outstanding, beginning of period	862,390	$ 5.42	1,040,500	$ 5.39	681,000	$ 5.16
Granted	43,636	25.44	—	—	372,500	5.95
Cancelled	(8,000)	5.13	(176,110)	5.20	—	—
Exercised	(177,642)	5.34	—	—	—	—
Forfeited	—	—	(2,000)	6.00	(13,000)	6.00
Outstanding, end of period	720,384	$ 6.66	862,390	$ 5.42	1,040,500	$ 5.39
Options exercisable at end of period	662,083	$ 5.55	711,213	$ 5.29	577,006	$ 5.18
Weighted average fair value of options granted with an exercise price equal to market price at grant	40,000	$ 4.50	—	—	372,500	$ 1.56
Weighted average fair value of options granted with an exercise price less than market price at grant	3,636	$ 7.58	—	—	—	—

The following table summarizes information about outstanding options as of December 31, 2004:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number	Weighted Average Remaining Term	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
$ 5.00-$7.00	666,748	0.4 Years	$ 5.38	651,780	$ 5.35
$10.00	10,000	0.4 Years	$ 10.00	6,667	$ 10.00
$19.50	30,000	9.0 Years	$ 19.50	—	$ —
$34.37	3,636	9.0 Years	$ 34.37	3,636	$ 34.37
$40.00	10,000	9.8 Years	$ 40.00	—	$ —
	720,384	0.9 Years	$ 6.66	662,083	$ 5.55

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 364,000. These modified options have been accounted for using variable accounting as of the option modification date. The Partnership applied variable accounting for the modified options until the holders elected to cash out the options or the election to cash out the options lapsed. CEI was responsible for paying the intrinsic value of the options for the holders who elected 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 Partnership ceased applying variable accounting for the remaining modified options. The Partnership recognized stock-based compensation expense of approximately $5.0 million related to the modified options for the year ended December 31, 2003.

In 2004, 85,000 restricted shares in CEI were issued to members of management under its long-term incentive plan with an intrinsic value of $2,579,000. 80,000 of the CEI restricted shares vest over a five-year period and 5,000 of the restricted shares vest over a three-year period. The intrinsic value of the restricted shares is amortized into stock-based compensation expense over the vesting periods.

(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 years ended December 31, 2004 and December 31, 2003. The computation of diluted earnings per unit further assumes the dilutive effect of unit options and restricted units.

Effective March 29, 2004, the Partnership completed a two-for-one split on its outstanding limited partnership units. All unit amounts for prior periods presented herein have been restated to reflect this unit split.

The following are the unit amounts used to compute the basic and diluted earnings per limited partner unit for the years ended December 31, 2004 and 2003 (in thousands, except per-unit amounts):

	Years Ended December 31,		
	2004	2003	December 17, 2002-December 31, 2002
Basic earnings per unit:			
Weighted average limited partner units outstanding	18,081	15,752	14,600
Dilutive earnings per unit:			
Weighted average limited partner units outstanding	18,081	15,752	14,600
Dilutive effect of restricted units	98	—	—
Dilutive effect of exercise of options outstanding	454	208	20
Dilutive units	18,633	15,960	14,620

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 (in thousands).

	2004		2003	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Cash and cash equivalents	$ 5,797	$ 5,797	$ 166	$ 166
Trade accounts receivable and accrued revenues	231,153	231,153	134,755	134,755
Fair value of derivative assets	3,191	3,191	4,080	4,080
Note receivable	1,653	1,653	1,563	1,563
Accounts payable, drafts payable and accrued gas purchases	255,700	255,700	136,761	136,761
Long-term debt	148,700	157,231	60,750	60,750
Fair value of derivative liabilities	2,219	2,219	2,278	2,278

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 carrying value for the note receivable approximates the fair value because this note earns interest based on the current prime rate.

The Partnership's long-term debt was comprised of borrowings under a revolving credit facility totaling $33.0 million and $20.0 million as of December 31, 2004 and 2003, 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, 2004, the Partnership also had borrowings totaling $115.0 million under senior secured notes with a weighted average interest rate of 6.95%. The fair value of these borrowings as of December 31, 2004 was adjusted to reflect to current market interest rate for such borrowings as of December 31, 2004.

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,	
	2004	2003
Fair value of derivative assets — current	$ 3,025	$ 4,080
Fair value of derivative assets — long term	166	—
Fair value of derivative liabilities — current	(2,085)	(2,278)
Fair value of derivative liabilities — long term	(134)	—
Net fair value of derivatives	$ 972	$ 1,802

Set forth below is the summarized notional amount and terms of all instruments held for price risk management purposes at December 31, 2004 (all quantities are expressed in British Thermal Units). The

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements — (Continued)

remaining term of the contracts extend no later than October 2007, with no single contract longer than 6 months. The Partnership's counterparties to derivative contracts include BP Corporation, UBS Energy and Total Gas & Power. As discussed in note 2, changes in the fair value of the Partnership's derivatives related to third-party producers and customers gas marketing activities are recorded in earnings in the period the transaction is entered into. The effective portion of changes in the fair value of cash flow hedges is recorded in accumulated other comprehensive income until the related anticipated future cash flow is recognized in earnings and the ineffective portion is recorded in earnings. Fair value hedges and their underlying physical are marked to market and the changes in their fair value are recorded in earnings as profit or loss on energy trading contracts.

December 31, 2004				
Transaction Type	**Total Volume**	**Pricing terms**	**Remaining Term of Contracts**	**Fair Value**
				(In thousands)
Cash Flow Hedge:				
Natural gas swaps cash flow hedge	2,088,000	Fixed prices ranging from $5.66 to $7.07 settling against	January 2005-December 2005	$ 69
Natural gas swaps cash flow hedge	(3,438,000)	various Inside FERC Index prices	January 2005-December 2005	$ (164)
Total natural gas swaps cash flow hedge				$ (95)
Natural gas liquids ("NGLS") swaps cash flow hedge	(1,633,716)	Fixed prices ranging from $0.5142 to $1.115 settling against Mt. Belvieu Average of daily postings (non-TET)	January 2005-March 2005	$ 122
Total NGL swaps cash flow hedge				$ 122
Mark to Market Derivatives:				
Swing swaps	3,209,690	Prices ranging from Inside FERC Index less $0.525 to Inside FERC Index plus $0.0075 settling against	January 2005 - March 2005	$ (31)
Swing swaps	(1,214,921)	various Inside FERC Index prices	January 2005 - March 2005	(7)
Total swing swaps mark to market hedges				$ (38)
Physical offset to swing swap transactions	1,214,921	Prices ranging from Inside FERC Index less $0.01 to Inside FERC Index settling against various	January 2005 - March 2005	—
Physical offset to swing swap transactions	(3,209,690)	Inside FERC Index prices	January 2005 - March 2005	(23)
Total physical offset to swing swaps				$ (23)
Third party on-system financial swaps	3,460,000	Fixed prices ranging from $4.83 to $7.225 settling against various	January 2005 - October 2007	$ (1,254)
Third party on-system financial swaps	(720,000)	Inside FERC Index prices	January 2005 - October 2007	439
Total third party on-system financial swaps				$ (815)

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Notes to Consolidated Financial Statements — (Continued)

December 31, 2004				
Transaction Type	**Total Volume**	**Pricing terms**	**Remaining Term of Contracts**	**Fair Value**
				(In thousands)
Physical offset to third party on-system transactions	420,000	Inside FERC Index prices Fixed prices ranging from $4.675 to	January 2005 - October 2007	$ (242)
Physical offset to third party on-system transactions	(3,160,000)	$6.93 settling against various	January 2005 - October 2007	$ 1,264
Total physical offset to marketing trading transactions swaps				$ 1,022
Marketing trading financial swaps	(450,000)	Fixed prices of $5.945 settling against Inside FERC Index Texas Eastern E. TX prices	January 2005- March 2005	$ 6
Total marketing trading financial swaps				$ 6
Physical offset to marketing trading transactions	450,000	Fixed prices of $5.855 settling against Inside FERC Index Texas Eastern E. TX prices	January 2005- March 2005	$ 19
Total physical offset to marketing trading transactions swaps				$ 19
Natural gas swaps	(85,000)	Fixed prices ranging from $9.335 to $9.38 settling against various Inside FERC Index prices	February 2005	$ 774
Total natural gas swaps				$ 774

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, 2004	$ 25	—	—	$ 25

(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 was 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, 2004, 2003 and 2002, the Partnership purchased natural gas from Camden in the amount of approximately $38.4 million, $8.4 million, and $10.1 million, respectively, and received approximately $2.4 million, $190,000, and $399,000, respectively, in treating fees from Camden.

Crosstex Pipeline Partners, L.P.

During the three years ended December 31, 2004, the Partnership was the general partner and a limited partner in CPP as discussed in Note 4. The Partnership had related-party transactions with CPP, as summarized below:

- During the years ended December 31, 2004, 2003 and 2002, the Partnership bought natural gas from CPP in the amount of approximately $11.6 million, $8.2 million and $3.4 million and paid approximately $51,000, $41,000 and $27,500, respectively, to CPP for transportation.
- During the years ended December 31, 2004, 2003 and 2002, 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, 2004, 2003 and 2002, the Partnership received distributions from CPP in the amount of approximately $159,000, $104,000 and $90,000, respectively.

(12) Commitments and Contingencies

(a) Leases-Lessee

The following table summarizes our remaining non-cancelable future payments under operating leases for leased office space, and office and field equipment with initial or remaining non-cancelable lease terms in excess of one year (in thousands).

2005	$ 1,817
2006	1,522
2007	1,398
2008	1,261
2009	1,199
Thereafter	1,518
	$ 8,715

Operating lease rental expense in the years ended December 31, 2004, 2003 and 2002, was approximately $2,849,000, $1,812,000, and $951,000, respectively.

(b) Leases —Lessor

During 2004 the Partnership leased approximately 15 of its treating plants to customers under operating leases. The initial terms on these leases are generally 24 months at which time the leases revert to 30-day cancellable leases. As of December 31, 2004, the Partnership only had four treating plants under operating leases with remaining non-cancellable lease terms in excess of one year. The future minimum lease rentals are $517,000 and $332,000 for the years ended December 31, 2005 and 2006, respectively. These leased treating plants have a cost of $3,792,000 and accumulated depreciation of $442,000 as of December 31, 2004.

(c) Employment Agreements

Certain members of management of the Partnership are parties to employment contacts with the general partner. The employment agreements provide those senior managers with severance payments in certain circumstances and prohibit each such person from competing with the general partner or its affiliates for a certain period of time following the termination of such person's employment.

(d) Environmental Issues

The Partnership acquired two assets from DEFS in June 2003 that have environmental contamination. These two assets were 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 had been identified at levels that exceeded 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 and sale agreement, DEFS retained the liability for cleanup of both the Conroe and Cadeville sites. Moreover, DEFS has entered into an agreement with a third-party company pursuant to which the remediation costs associated with the Conroe site have been assumed by this third-party company that specializes in remediation work. In addition, effective September 1, 2004, the Partnership sold its Cadeville assets, including the compressor station and gathering system, subject to the retained DEFS indemnity, to a third party. Therefore, the Company does not expect to incur any material environmental liability associated with the Conroe or Cadeville sites.

The Partnership acquired LIG Pipeline Company, and its subsidiaries, on April 1, 2004. Contamination from historical operations was identified during due diligence at a number of sites owned by the acquired companies. The seller, AEP, has indemnified the Partnership for these identified sites. Moreover, AEP has entered into an agreement with a third-party company pursuant to which the remediation costs associated with these sites have been assumed by this third-party company that specializes in remediation work. The Partnership does not expect to incur any material liability with these sites. In addition, the Partnership has disclosed possible Clean Air Act monitoring deficiencies it has discovered to the Louisiana Department of Environmental Quality and is working with the Department to correct these deficiencies and to address modifications to facilities to bring them into compliance. The Partnership does not expect to incur any material environmental liability associated with these issues.

(e) 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.

In May 2003, four landowner groups filed suit against the Partnership in the 267th Judicial District Court in Victoria County, Texas seeking damages related to the expiration of an easement for a segment of one of its pipelines located in Victoria County, Texas. In 1963, the original owners of the land granted an easement for a term of 35 years, and the prior owner of the pipeline failed to renew the easement. The Partnership filed a condemnation counterclaim in the district count suit and it filed, in a separate action in the county court, a condemnation suit seeking to condemn a 1.38-mile long easement across the land. Pursuant to condemnation procedures under the Texas Property Code, three special commissioners were appointed to hold a hearing to determine the amount of the landowner's damages. In August 2004, a hearing was held and the special commissioners awarded damages to the current landowners in the amount of $877,500. The Partnership has timely objected to the award of the special commissioners and the condemnation case will now be tried in the county court. The damages award by the special commissioners will have no effect and cannot be introduced as evidence in the trial. The county court will determine the amount that the Partnership will pay the current landowners for an easement across their land and will determine whether or not and to what extent the current landowners are entitled to recover any damages for the time period that there was not an easement for the pipeline on their land. Under the Texas Property Code, in order to maintain possession of and continued use of the pipeline until the matter has been resolved in the county court, the Partnership was required to post bonds and cash, each totaling the amount of $877,500, which is the amount of the special commissioners award. The Partnership is not able to predict the ultimate outcome of this matter.

In March 2005 the Partnership received a claim of approximately $700,000 for damages and lost profits from one of its customers. The claim relates to an October 2004 incident in which natural gas liquids, which can drop out of the gas stream in pipelines and tend to clog the lines, were being removed from one of our lines pursuant to normal operating procedures. Some of the liquids may have inadvertently been diverted to the customer’s facilities. The Partnership has no basis at this time to evaluate the merits of the customer’s claim or to reasonably estimate any potential liability we may have.

(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 LIG pipelines and processing plants located in Louisiana and various other small systems. Also included in the Midstream division are the Partnership’s Producer Services operations. The operations in the Midstream segment are similar in the nature of the products and services, the nature of the production processes, the type of customer, the methods used for distribution of products and services and the nature of the regulatory environment. The Treating division generates fees from its plants either through volume-based treating contracts or though fixed monthly payments. Included in the Treating division are four gathering systems that are connected to the treating plants and the Seminole plant located in Gaines County, Texas. During 2004, management decided that the Seminole plant, which was acquired in June 2003, should be included in the Treating division. Therefore, the 2003 segment information has been adjusted to reflect this reclassification.

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 and stock based compensation are allocated to the segments on a pro rata basis based on the number of employees within the segments. Interest expense is allocated on a pro rata basis based on segment assets. Inter-segment sales are at cost.

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements — (Continued)

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, 2004:			
Sales to external customers	$ 1,948,021	$ 30,755	$ 1,978,776
Inter-segment sales	6,360	(6,360)	—
Interest expense	7,801	1,419	9,220
Stock-based compensation	816	185	1,001
Depreciation and amortization	15,762	7,272	23,034
Segment profit (loss)	20,390	3,765	24,155
Segment assets	496,484	90,287	586,771
Capital expenditures	20,843	25,141	45,984
Year ended December 31, 2003:			
Sales to external customers	$ 989,697	$ 23,966	$ 1,013,663
Inter-segment sales	6,893	(6,893)	—
Interest expense	2,747	645	3,392
Stock-based compensation	4,276	1,069	5,345
Depreciation and amortization	9,349	3,919	13,268
Segment profit (loss)	12,363	2,863	15,226
Segment assets	296,417	69,633	366,050
Capital expenditures	28,728	10,275	39,003
Year ended December 31, 2002:			
Sales to external customers	$ 437,432	$ 14,817	$ 452,249
Inter-segment sales	4,073	(4,073)	—
Interest expense	2,327	390	2,717
Impairments	—	4,175	4,175
Depreciation and amortization	5,738	2,007	7,745
Segment profit (loss)	1,613	(1,269)	344
Segment assets	199,803	33,382	233,185
Capital expenditures	11,154	3,391	14,545

(14) Quarterly Financial Data (Unaudited)

Summarized unaudited quarterly financial data is presented below.

	First	Second	Third	Fourth	Total
	(In thousands, except per unit data)				
2004					
Revenues	$ 325,358	$ 515,531	$ 508,884	$ 629,003	$ 1,978,776
Operating income	6,799	8,213	8,806	8,759	32,577
Net income	5,706	5,941	5,945	6,112	23,704
Earnings per limited partner unit — basic	$ 0.26	$ 0.25	$ 0.24	$ 0.23	$ 0.98
Earnings per limited partner unit — diluted	$ 0.24	$ 0.24	$ 0.23	$ 0.22	$ 0.95
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	832	4,975	3,888	5,531	15,226
Earnings per limited partner unit — basic	$ 0.06	$ 0.33	$ 0.22	$ 0.28	$ 0.89
Earnings per limited partner unit — diluted	$ 0.06	$ 0.32	$ 0.21	$ 0.27	$ 0.88

Schedule II

CROSSTEX ENERGY, L.P.

	Balance at Beginning of Period	Charged to Costs and Expenses	Deductions	Balance at End of Period
		(In thousands)		
Year ended December 31, 2004				
Allowance for doubtful accounts	—	$ 59	—	$ 59
Year ended December 31, 2003				
Allowance for doubtful accounts	—	—	—	—
Year ended December 31, 2002				
Allowance for doubtful accounts	$ 5,776	—	(5,776)(a)	—

(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.

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EXHIBIT INDEX

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	—	Second Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of March 29, 2004 (incorporated by reference to Exhibit 3.2 to our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004).
3.3	—	Amendment No. 1 to Second Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of April 1, 2004 (incorporated by reference to Exhibit 3.3 to our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004).
3.4	—	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).
3.5	—	Second Amended and Restated Agreement of Limited Partnership of Crosstex Energy Services, L.P., dated as of April 1, 2004 (incorporated by reference to Exhibit 3.5 to our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004).
3.6	—	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).
3.7	—	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).
3.8	—	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).
3.9	—	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 (incorporated by reference to Exhibit 10.3 to our Annual Report on Form 10-K for the year ended December 31, 2003).
10.4	—	Third Amendment to Second Amended and Restated Credit Agreement, dated as of April 1, 2004, by and 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 Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004).
10.5	—	Fourth Amendment to Second Amended and Restated Credit Agreement, dated as of June 18, 2004, by and 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 Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004).
10.6	—	$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).
10.7	—	Letter Amendment No. 1 to Master Shelf Agreement, dated as of April 1, 2004, among Crosstex Energy Services, L.P., Prudential Investment Management, Inc., The Prudential Insurance Company of America and Pruco Life Insurance Company (incorporated by reference to Exhibit 10.2 to our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004).

Number		Description
10.8	—	Letter Amendment No. 2 to Master Shelf Agreement, dated as of June 18, 2004, among Crosstex Energy Services, L.P., Prudential Investment Management, Inc., The Prudential Insurance Company of America and Pruco Life Insurance Company (incorporated by reference to Exhibit 10.2 to our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004).
10.9	—	Purchase and Sale Agreement, dated as of February 13, 2004, by and between AEP Energy Services Investments, Inc. and Crosstex Energy, L.P. (incorporated by reference to Exhibit 2.1 to our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004).
10.10	—	First Amendment to Purchase and Sale Agreement, dated as of February 13, 2004, by and between AEP Energy Services Investments, Inc. and Crosstex Energy, L.P. (incorporated by reference to Exhibit 2.2 to our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004).
10.11	—	Second Amendment to Purchase and Sale Agreement, dated as of April 1, 2004, by and between AEP Energy Services Investments, Inc. and Crosstex Louisiana Energy, L.P. (incorporated by reference to Exhibit 2.3 to our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004).
10.12	—	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).
10.13	—	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).
10.14†	—	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).
10.15	—	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).
10.16†	—	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).
10.17	—	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).
10.18	—	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).
10.19	—	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).
10.20	—	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.

† As required by Item 14(a)(3), this exhibit is identified as a compensatory benefit plan or arrangement

List of Subsidiaries

Exhibit 21.1

Name of Subsidiary	State of Organization
Crosstex Operating GP, LLC	Delaware
Crosstex Energy Services GP, LLC	Delaware
Crosstex Energy Services, L.P.	Delaware
Crosstex Pipeline, LLC	Texas
Crosstex Pipeline Partners, Ltd.	Texas
Crosstex Gulf Coast Transmission Ltd.	Texas
Crosstex Gulf Coast Marketing Ltd.	Texas
Crosstex CCNG Gathering, Ltd.	Texas
Crosstex CCNG Transmission, Ltd.	Texas
Crosstex CCNG Processing, Ltd.	Texas
Crosstex Treating Services, L.P.	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
Crosstex Louisiana Energy, L.P.	Delaware
LIG Chemical GP, LLC	Delaware
LIG Chemical, L.P.	Delaware
LIG Liquids Holdings, L.P.	Delaware
Crosstex LIG, LLC	Louisiana
Crosstex Tuscaloosa, LLC	Louisiana
Crosstex LIG Liquids, LLC	Louisiana
Crosstex DC Gathering Company, J.V.	Texas
Crosstex North Texas Pipeline, L.P.	Texas
Crosstex North Texas Gathering, L.P.	Texas

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

The Partners of
Crosstex Energy, L.P.:

We consent to the incorporation by reference in the registration statements on Forms S-3 (No. 333-116538), and S-8 of Crosstex Energy, L.P. (No. 333-107025) of our reports dated March 14, 2005, with respect to the consolidated balance sheets of Crosstex Energy, L.P. as of December 31, 2004 and 2003, 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, 2004, and all related financial statement schedules, management's assessment of the effectiveness of internal control over financial reporting as of December 31, 2004 and the effectiveness of internal control over financial reporting as of December 31, 2004, which reports appear herein.

KPMG LLP

Dallas, Texas
March 14, 2005

Exhibit 31.1

CERTIFICATIONS

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

1. I have reviewed this 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 officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15(d)-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused 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) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with general accepted accounting principles;

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

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in 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 officers and I have disclosed, based on our most recent evaluation of internal controls over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

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

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

/s/ BARRY E. DAVIS

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

Date: March 14, 2005

Exhibit 31.2

CERTIFICATIONS

I, William W. Davis, Executive Vice President and Chief Financial Officer of Crosstex Energy GP, LLC, the general partner of Crosstex Energy GP, L.P., the general partner of the registrant, certify that:

1. I have reviewed this 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 officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15(d)-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused 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) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with general accepted accounting principles;

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

(a) 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 officers and I have disclosed, based on our most recent evaluation of internal controls over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

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

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

/s/ WILLIAM W. DAVIS

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

Date: March 14, 2005

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 year ended December 31, 2004 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, the general partner of Crosstex Energy GP, L.P., the general partner of the Registrant, and William W. Davis, Chief Financial Officer of Crosstex Energy GP, LLC, the general partner of Crosstex Energy GP, L.P., the general partner of the Registrant, 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

Date: Mach 14, 2005

Barry E. Davis
Chief Executive Officer

/s/ William W. Davis

Date: Mach 14, 2005

William W. Davis
Chief Executive Officer

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.