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, 2006

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission file number: 000-50067

CROSSTEX ENERGY, L.P.

(Exact name of registrant as specified in its charter)

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

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

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

Title of Each Class	Name of Exchange on Which Registered
Common Units Representing Limited Partnership Interests	The NASDAQ Global Select Market

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

Senior Subordinated Series C Units

Indicate by check mark if registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☑

Indicate by check mark if registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☑

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 a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☐ Accelerated filer ☑ Non-accelerated filer ☐

Indicate by check mark whether the registrant is a shell company (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 $386,398,616 on June 30, 2006, based on $36.78 per unit, the closing price of the Common Units as reported on the NASDAQ National Market on such date.

At February 16, 2007, there were 21,979,035 common units, 4,668,000 subordinated units, and 12,859,650 senior subordinated series C units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:

None.

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List of Subsidiaries
Consent of KPMG LLP
Certification of the Principal Executive Officer
Certification of the Principal Financial Officer
Certification Pursuant to 18 U.S.C. Section 1350

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 Global Select 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 "Investors" 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," "us" and "its," are sometimes used as abbreviated references to Crosstex Energy, L.P. itself or Crosstex Energy, L.P. together with its consolidated subsidiaries, including the Operating Partnership.

We are an independent midstream energy company engaged in the gathering, transmission, treating, processing and marketing of natural gas and natural gas liquids, or NGLs. 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 NGLs, fractionate NGLs into purity products and market those products for a fee, transport natural gas and ultimately provide 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. We operate processing plants that process gas transported to the plants by major interstate pipelines or from our own gathering lines under a variety of fee arrangements. 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.

We have two operating segments, Midstream and Treating. Our Midstream division focuses on the gathering, processing, transmission and marketing of natural gas and NGLs, while our Treating division focuses on the removal of impurities from natural gas to meet pipeline quality specifications. Our primary Midstream assets include approximately 5,000 miles of natural gas gathering and transmission pipelines, 12 natural gas processing plants and four fractionators. 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 our fractionators separate the NGLs into separate NGL products, including ethane, propane, iso- and normal butanes and natural gasoline. Our primary Treating assets include approximately 210 natural gas amine-treating plants and 43 dew point control plants. Our natural gas treating plants remove carbon dioxide and hydrogen sulfide from natural gas prior to delivering the gas into pipelines to ensure that it meets pipeline quality specifications. See Note 13 to the consolidated financial statements for financial information about these operating segments.

Set forth in the table below is a list of our acquisitions since January 1, 2003.

Acquisition	Acquisition Date	Purchase Price (In thousands)	Asset Type
DEFS Acquisition	June 2003	$68,124	Gathering and transmission systems and processing plants
LIG Acquisition	April 2004	73,692	Gathering and transmission systems and processing plants
Crosstex Pipeline Partners	December 2004	5,100	Gathering pipeline
Graco Operations	January 2005	9,257	Treating plants
Cardinal Gas Services	May 2005	6,710	Treating plants and gas processing plants
El Paso Acquisition	November 2005	480,976	Processing and liquids business (including 23.85% interest in Blue Water gas processing plant)
Hanover Amine Treating	February 2006	51,700	Treating plants
Blue Water Acquisition	May 2006	16,454	Additional 35.42% interest in gas processing plant
Chief Acquisition	June 2006	475,287	Gathering and transmission systems and carbon dioxide treating plant
Cardinal Gas Solutions	October 2006	6,330	Dew point control plants and treating plants

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. Crosstex Energy GP, L.P. and Crosstex Energy GP, LLC are indirect, wholly-owned subsidiaries of Crosstex Energy, Inc., or CEI.

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

/d = per day
Bcf = billion cubic feet
Btu = British thermal units
Mcf = thousand cubic feet
MMBtu = million British thermal units
MMcf = million cubic feet
NGL = natural gas liquid

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 and NGLs; accomplishing economies of scale through new construction or expansion in core operating areas; improving the profitability of our assets by increasing their utilization while controlling costs; 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 expansion projects located in north Louisiana and north Texas 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 and treating 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, primarily through the acquisition or development of key assets that will serve as a platform for further growth. We established new core areas through the acquisition and consolidation of our south Texas assets in 2001 through 2003 and the acquisition of LIG Pipeline Company and subsidiaries, which we collectively refer to as LIG, in 2004, and the ongoing work to consolidate with the 2005 acquisition of the south Louisiana processing business from El Paso Corporation, or El Paso. With the acquisition of the natural gas gathering pipeline systems and related facilities from Chief Holdings LLC, or Chief, and the completion of construction of the North Texas Pipeline, or NTP, in 2006, we have established a core area in north Texas.
- *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. In April 2006, we completed construction and commenced operations on our new 133-mile NTP to transport gas from the Barnett Shale. We are in the process of expanding capacity on the NTP, as well as expanding our north Texas processing capacity and completing the buildout of our north Texas gathering system acquired in the Chief acquisition in response to the increased producer activity in this area. We also have underway a major expansion of the LIG system that is expected to commence operation in 2007, as discussed in detail below. We continue to pursue organic growth opportunities in Texas, Louisiana and elsewhere.
- *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. As part of this process, we focus on providing a full range of services to 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. Treating services are not provided by many of our competitors, which gives us an additional advantage in competing for new supply when gas requires treating to meet pipeline specifications. Furthermore, we emphasize increasing the percentage of our natural gas and NGLs sales directly to end users, such as industrial and utility consumers, in an effort to increase our operating margins.

Recent Acquisitions and Expansion

Chief Midstream Assets. On June 29, 2006, we acquired the natural gas gathering pipeline systems and related facilities of Chief in the Barnett Shale for $475.3 million. The acquired systems, which we refer to in conjunction with the NTP as our North Texas Assets, consist of approximately 226 miles of existing pipeline with up to an additional 400 miles of planned pipelines, located in Parker, Tarrant, Denton, Palo Pinto, Erath, Hood, Somervell, Hill and Johnson Counties, Texas. The acquired assets also include a 125 million cubic feet per day carbon dioxide treating plant and compression facilities with 26,000 horsepower. At the closing of that acquisition, approximately 160,000 net acres previously owned by Chief and acquired by Devon Energy Corporation, or Devon, simultaneously with our acquisition, as well as 60,000 net acres owned by other producers, were dedicated to the systems. Immediately following the closing of the Chief acquisition, we began expanding our north Texas pipeline gathering system.

North Texas Pipeline System. In April 2006, we completed construction and commenced service on the NTP, a new 133-mile pipeline and associated gathering lines from an area near Fort Worth, Texas to a point near Paris, Texas, with capacity of approximately 250,000 MMBtu/d. The NTP connects production from the Barnett Shale to markets in north Texas and to markets accessed by the Natural Gas Pipeline Company, or NGPL pipeline and other markets. The NTP allows contracted gas to flow to markets that were not previously available to some key Barnett Shale producers. We plan to expand the NTP in the first quarter of 2007 to a total capacity of approximately 375,000 MMBtu/d. The NTP will interconnect with a new intrastate gas pipeline to be constructed by Boardwalk Pipeline Partners, L.P. known as the Gulf Crossing Pipeline. The Gulf Crossing Pipeline will provide our customers access to premium midwest and east coast markets. We have committed to contract for 150,000 MMBtu/d for ten years of firm transportation capacity on the Gulf Crossing Pipeline when it commences service, which is expected in the latter part of 2008.

North Louisiana Expansion Project. Our North Louisiana Expansion project is an extension of our LIG system which is designed to better serve Louisiana intrastate markets and interstate markets, and to provide additional and much needed take-away pipeline capacity to the producers developing natural gas in the fields south of Shreveport, Louisiana. The expansion consists of 63 miles of 24” mainline with 9 miles of 16” gathering lateral pipeline and 10,000 horsepower of compression. Interconnects on the North Louisiana Expansion include connections with the interstate pipelines of ANR Pipeline, Columbia Gulf Transmission, Texas Gas Transmission and Trunkline Gas with additional interconnects under consideration. The capacity of the expansion is approximately 250 MMcf/d. Four of the largest suppliers of natural gas committed to the new pipeline are El Paso Production, JW Operating, KCS Resources and Winchester Production, which together have committed 185 MMcf/d of capacity. The pipeline is expected to be partially operational in late March 2007 with total completion expected by early May 2007.

Blue Water Processing Plant Acquisition. In May 2006, we acquired an additional 35.42% interest in the Blue Water gas processing plant for $16.5 million, increasing our total ownership interest to 59.27%. We also became the operator of the plant in May 2006. Our initial 23.85% interest in this processing plant was acquired as part of our November 2005 El Paso acquisition.

Cardinal Treating Assets. On October 2, 2006, we acquired the treating and dew point control business of Cardinal Gas Solutions, L.P. for $6.3 million. The acquired assets include 10 dew point control plants and seven amine treating plants.

Hanover Treating Assets. On February 1, 2006, we acquired 48 amine treating plants from a subsidiary of Hanover Compression Company for $51.7 million.

Other Developments

Issuance of Senior Subordinated Series C Units. On June 29, 2006, we issued an aggregate of 12,829,650 senior subordinated series C units representing limited partner interests in a private equity offering for net proceeds of $359.3 million. The senior subordinated series C units were issued at $28.06 per unit, which represented a discount of 25% to the market value of common units on such date. CEI purchased 6,414,830 of the senior subordinated series C units. In addition, Crosstex Energy GP, L.P. made a general partner contribution of $9.0 million in connection with this issuance to maintain its 2% general partner interest. The senior subordinated series C units will automatically convert to common units on the first date on or before February 16, 2008 that conversion is permitted by our partnership agreement at a ratio of one common unit for each senior subordinated series C unit.

Bank Credit Facility. On June 29, 2006, we amended our bank credit facility to, among other things, provide for revolving credit borrowings up to a maximum principal amount of $1.0 billion. The bank credit agreement includes procedures for additional financial institutions selected by us to become lenders under the agreement, or for any existing lender to increase its commitment in an amount approved by us and the lender, subject to a maximum of $300 million for all such increases in commitments of new or existing lenders. The maturity date was also extended to June 2011.

Senior Secured Notes. In March and July 2006, we amended the shelf agreement governing the senior secured notes to increase our availability from $200.0 million to $510.0 million. In March 2006, we issued $60.0 million aggregate principal amount of senior secured notes with an interest rate of 6.32% and a maturity of ten years. In July 2006, we issued $245.0 million aggregate principal amount of senior secured notes with an interest rate of 6.96% and a maturity of ten years. Proceeds were used to pay indebtedness under our bank credit facility.

Midstream Segment

Gathering, Processing 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 5,000 miles of pipeline, 12 natural gas processing plants and four fractionators and contributed approximately 79% and 76% of our gross margin in 2006 and 2005, respectively.

- *South Louisiana Processing Assets.* Our Louisiana natural gas processing and liquids business, which was acquired on November 1, 2005 and is referred to as our South Louisiana Processing Assets, includes a total of 2.3 Bcf/d of processing capacity, 66,000 barrels per day of fractionation capacity, 2.4 million barrels of underground storage and 400 miles of liquids transport lines.

  Our South Louisiana Processing Assets primarily consist of:

  - *Eunice Processing Plant and Fractionation Facility.* The Eunice facilities are located near Eunice, Louisiana. The Eunice processing plant has a capacity of 1.2 Bcf/d and processed approximately 756 MMcf/d for the year ended December 31, 2006. The plant is connected to onshore, continental shelf and deepwater gas production and has downstream connections to the ANR Pipeline, Florida Gas Transmission and Texas Gas Transmission. The Eunice fractionation facility has a capacity of 36,000 barrels per day of liquid products. This facility also has 190,000 barrels of above-ground storage capacity. The fractionation facility produces ethane, propane, iso-butane, normal butane and natural gasoline for various customers. The fractionation facility is directly connected to the southeast propane market and pipelines to the Anse La Butte storage facility. We have a five-year storage agreement at the Anse La Butte facility for 100,000 barrels of NGL storage beginning January 1, 2007.

  - *Pelican Processing Plant.* The Pelican processing plant complex is located in Patterson, Louisiana and has a designed capacity of 600 MMcf/d of natural gas. For the year ended December 31, 2006, the plant processed approximately 370 MMcf/d. The Pelican plant is connected with continental shelf and deepwater production and has downstream connections to the ANR Pipeline.

  - *Sabine Pass Processing Plant.* The Sabine Pass processing plant is located 15 miles east of the Sabine River at Johnson's Bayou, Louisiana and has a processing capacity of 300 MMcf/d of natural gas. The Sabine Pass plant is connected to continental shelf and deepwater gas production with downstream connections to Florida Gas Transmission, Tennessee Gas Pipeline and Transco. For the year ended December 31, 2006, this facility processed approximately 217 MMcf/d.

  - *Blue Water Gas Processing Plant.* We acquired a 23.85% interest in the Blue Water gas processing plant in the November 2005 El Paso acquisition and acquired an additional 35.42% interest in May 2006, at which time we became the operator of the plant. The plant has a net capacity to our interest of 186 MMcf/d. For the year ended December 31, 2006, this facility processed approximately 127 MMcf/d net to our interest. The Blue Water plant is located near Crowley, Louisiana. The Blue Water facility is connected to continental shelf and deepwater production volumes through the Blue Water pipeline system. Downstream connections from this plant include the Tennessee Gas Pipeline and Columbia Gulf. The facility also performs liquid natural gas (LNG) conditioning services for the Excelerate Energy LNG tanker unloading facility.

- *Riverside Fractionation Plant.* The Riverside fractionator and loading facility is located on the Mississippi River upriver from Geismar, Louisiana. The Riverside plant has a fractionation capacity of 28,000 to 30,000 barrels per day of liquids products and fractionates liquids delivered by the Cajun Sibon pipeline system from the Pelican, Blue Water and Cow Island plants or by truck. The Riverside facility has above-ground storage capacity of approximately 102,000 barrels.
- *Napoleonville Storage Facility.* The Napoleonville NGL storage facility is connected to the Riverside facility and has a total capacity of approximately 2.4 million barrels of underground storage.
- *Cajun Sibon Pipeline System.* The Cajun Sibon pipeline system consists of approximately 400 miles of 6" and 8" pipelines with a system capacity of approximately 28,000 Bbls/day. The pipeline transports unfractionated NGLs, referred to as raw make, from the Pelican plant and the Blue Water plant to either the Riverside fractionator or the Napoleonville storage facility. Alternate deliveries can be made to the Eunice plant.

We contracted to buy our South Louisiana Processing Assets from El Paso two weeks before Hurricane Katrina struck the Gulf Coast, and approximately six weeks before Hurricane Rita struck. While the hurricanes did not do any significant damage to our South Louisiana Processing Assets, both hurricanes did extensive damage to Gulf of Mexico drilling, production and transportation facilities. In addition, as a result of the hurricanes, drilling activity in the Gulf of Mexico since that time has been reduced, resulting in an exacerbation of declining trends for production in the area. We estimate that Gulf of Mexico production is 20-25% below pre-hurricane levels, and as a result, we have lower volumes in the plants than we estimated at the time of the acquisition. This has resulted in 2006 cash flows from our South Louisiana Processing Assets at levels significantly below levels we had anticipated at the time of the acquisition. In addition, a pipeline that supplies natural gas to our Eunice processing plant unilaterally changed the methodology used to allocate fuel and losses. These changes, may result in increased expenses associated with the Eunice Plant operations for us and our customers. We are currently in negotiations with the pipeline supplier and evaluating our remedies. We are evaluating alternative strategies for the operation of these assets that we believe will significantly improve cash flows.

- *North Texas Assets.* On June 29, 2006, we acquired the natural gas gathering pipeline systems and related facilities of Chief in the Barnett Shale. The acquired systems consist of approximately 226 miles of existing pipeline with up to an additional 400 miles of planned pipelines, located in Parker, Tarrant, Denton, Palo Pinto, Erath, Hood, Somervell, Hill and Johnson counties, Texas. The acquired assets also include a 125 million cubic feet per day carbon dioxide treating plant and compression facilities with 26,000 horsepower. At the closing of that transaction, approximately 160,000 net acres previously owned by Chief and acquired by Devon simultaneously with our acquisition, as well as 60,000 net acres owned by other producers, were dedicated to the systems. Immediately following the closing of the Chief acquisition, we began expanding our north Texas pipeline gathering system. As of December 31, 2006, we had installed approximately 49 miles of gathering pipeline and connected 85 new wells to our gathering system, 46 of which are owned or controlled by Devon and 39 of which are owned or controlled by other producers. In addition to expanding our gathering system, we had installed 4,400 horsepower of additional compression to handle the increased volumes. We also installed a new 55,000 Mcf/d cryogenic processing plant, referred to as our Azle plant, and added inlet refrigeration to an existing 30,000 Mcf/d plant in order to remove hydrocarbon liquids from growing gas streams. We have increased total throughput on this gathering system from approximately 115 MMcf/d at the time of the acquisition to approximately 230 MMcf/d for the month of December 2006.

  - We plan to expand our NTP system in the second quarter of 2007 to a total capacity of approximately 375,000 MMBtu/day.
  - We have committed to contract for 150,000 MMBtu/day of firm transportation capacity on a new interstate gas pipeline to be constructed by Boardwalk Pipeline Partners, L.P. known as the Gulf Crossing

Pipeline, which will connect with our NTP system in Lamar County, Texas. The Gulf Crossing Pipeline will provide our customers access to premium midwest and east coast markets.

- *LIG System.* We acquired the LIG system on April 1, 2004. The LIG system is the largest intrastate pipeline system in Louisiana, consisting of approximately 2,000 miles of gathering and transmission pipeline, and had an average throughput of approximately 692,000 MMBtu/d for the year ended December 31, 2006. The system also includes two operating processing plants with an average throughput of 328,000 MMBtu/day for the year ended December 31, 2006. The system has access to both rich and lean gas supplies. These supplies reach from north Louisiana to new 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 industrial Mississippi River corridor between Baton Rouge and New Orleans. We are extending our LIG system to better serve our customers. The North Louisiana Expansion consists of 63 miles of 24" mainline with 9 miles of gathering lateral pipeline and 10,000 horsepower of compression. The capacity of the expansion is approximately 250 MMcf/d. The pipeline is expected to be partially operational in late March 2007 with total completion expected by early May 2007.
- *South Texas System.* We have assembled a highly-integrated south Texas system comprised of approximately 1,400-miles of intrastate gathering and transmission pipelines and a processing plant with a processing capacity of approximately 150 MMcf/day. The south Texas system was built through a number of acquisitions and follow-on organic projects, including acquisitions of the Gulf Coast system, the Corpus Christi system, the Gregory gathering system and processing plant, the Hallmark system and the Vanderbilt system. Average throughput on the system for the year ended December 31, 2006 was approximately 457,000 MMBtu/d. Average throughput in the processing plant was approximately 99,000 MMBtu/d for that period. The system gathers gas from major production areas in the Texas gulf coast and delivers gas to the industrial markets, power plants, other pipelines and gas distribution companies in the region from Corpus Christi to the Houston area.

Other Midstream assets and activities include:

- *Mississippi Pipeline System.* This approximately 603-mile system in south Mississippi gathers wellhead supply in the region and sells it through direct market connections to utilities and industrial end-users. Average throughput on the system was approximately 107,000 MMbtu/d for the year ended December 31, 2006.
- *Arkoma Gathering System.* This approximately 140-mile low-pressure gathering system in southeastern Oklahoma delivers gathered gas into a mainline transmission system. For the year ended December 31, 2006, throughput on the system averaged approximately 22,000 MMbtu/d.
- *Other.* Other midstream assets consist of a variety of gathering lines and a processing plant with a processing capacity of approximately 66,000 MMbtu/day. Total volumes gathered and resold were approximately 65,000 MMbtu/d for the year ended December 31, 2006. Total volumes processed were approximately 22,000 MMBtu/day in the period.
- *Off-System Services.* We offer natural gas marketing services on behalf of producers for natural gas that does not move on our assets. We market this gas on a number of interstate and intrastate pipeline. These volumes averaged approximately 139,000 MMbtu/d in 2006.

Treating Segment

We operate (or lease to producers for operation) treating plants that 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 21% and 24% of our gross margin in 2006 and 2005, respectively. Our treating business has grown from 112 plants in operation at December 31, 2005 to 160 plants in operation at December 31, 2006. During 2006, we spent an aggregate of $58.0 million in two separate acquisitions to acquire 55 treating plants, 10 dew point control plants and related spare parts inventory. Pipeline companies have begun enforcing gas quality specifications to lower the dew point of the gas they receive and transport. A higher relative dew point can sometimes cause liquid hydrocarbons to condense in the pipeline and cause operating problems and gas quality issues to the downstream markets. Hydrocarbon dew point plants are skid mounted process equipment that remove these hydrocarbons. Typically these plants use a Joules-Thompson expansion process to lower the temperature of the gas stream and collect the liquids before they enter the downstream pipeline. Our Treating division views dew point control as complementary to our treating business.

We believe we have the largest gas treating operation in the Texas and Louisiana gulf coast. Natural gas from certain formations in the Texas gulf coast, as well as other locations, is high in carbon dioxide, which generally needs to be removed before introduction of the gas into transportation pipelines. Many 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.

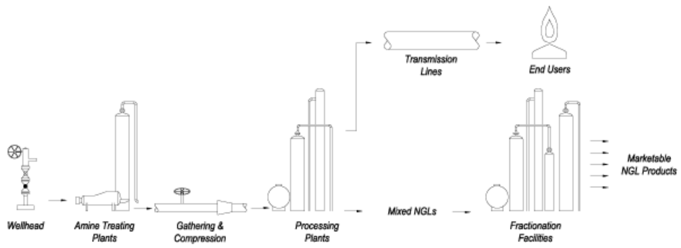
We also own an undivided 12.4% interest in the Seminole gas processing plant, which is located in Gaines County, Texas. We account for that interest as part of our Treating division. The Seminole plant has dedicated long-term reserves from the Seminole San Andres unit to which it also supplies carbon 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 $0.68 for each Mcf of carbon dioxide returned. The owners of the Seminole plant also receive 50% of the NGLs produced by the plant.

Our treating growth strategy is based on the belief that if gas prices remain at recent levels it will encourage drilling deeper gas formations. We believe the gas recovered from these deep formations is more likely to be high in carbon dioxide. 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 remove the impurities from the gas. After mixing, gas and reacted 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. Our 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 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 and transmission pipelines to ensure that it meets pipeline quality specifications. Pipeline companies have begun enforcing gas quality specifications to lower the dew point of the gas they receive and transport. A higher relative dew point can sometimes cause liquid hydrocarbons to condense in the pipeline and cause operating problems and gas quality issues to the downstream markets. Hydrocarbon dew point plants are skid mounted process equipment that remove these hydrocarbons. Typically these plants use a Joules-Thompson expansion process to lower the temperature of the gas stream and collect the liquids before they enter the downstream pipeline. Our Treating division views dew point control as complementary to our treating business.

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. Natural gas produced by a well may not be 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, processing plants, and gathering systems and deliver it to industrial end-users, utilities and to other pipelines.

Supply/Demand Balancing

As we purchase natural gas, we establish a margin normally by selling natural gas for physical delivery to third-party users. We can also use over-the-counter derivative instruments or enter 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 gathering, transmission, treating, processing and marketing services for natural gas and NGLs is highly competitive. We face strong competition in obtaining natural gas supplies and in the marketing and transportation of natural gas and NGLs. Our competitors include major integrated oil companies, interstate and intrastate pipelines and other natural gas gatherers and processors. Competition for natural gas supplies is primarily based on geographic location of facilities in relation to production or markets, the reputation, efficiency and reliability of the gatherer and the pricing arrangements offered by the gatherer. Many of our competitors offer more services or have greater financial resources and access to larger natural gas supplies than we do. Our competition will likely differ in different geographic areas.

Our gas treating operations face competition from manufacturers of new treating and dew point control 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 addition, we routinely lose business to gas gatherers who have underutilized treating or processing capacity and can take the producers' gas without requiring wellhead treating. We may also lose wellhead treating opportunities to blending. Some pipeline companies have the limited ability to waive their quality specifications and allow producers to deliver their contaminated gas untreated. This is generally referred to as blending because of the receiving company's ability to blend this gas with cleaner gas in the pipeline such that the resulting gas meets pipeline specification.

In marketing natural gas and NGLs, 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.

We face strong competition for acquisitions and development of new projects from both established and start-up companies. Competition increases the cost to acquire existing facilities or businesses, and results in fewer commitments and lower returns for new pipelines or other development projects. Many of our competitors have greater financial resources or lower capital costs, or are willing to accept lower returns or greater risks. Our competition differs by region and by the nature of the business or the project involved.

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 and relatively limited benefit 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, 2006, we had one customer that accounted for approximately 13.4% of our consolidated revenues. 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, or FERC, does not directly regulate our operations under the National Gas Act (NGA). However, FERC's regulation of interstate natural gas pipelines 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; and

- the initiation and discontinuation of services.

The rates, terms and conditions of service under which we transport natural gas in our pipeline systems in interstate commerce are subject to FERC jurisdiction under Section 311 of the Natural Gas Policy Act, or NGPA. Rates for services provided under Section 311 of the NGPA may not exceed a "fair and equitable rate", as defined in the NGPA. The rates are generally subject to review every three years by FERC or by an appropriate state agency. Rates for interstate services provided under NGPA Section 311 on our south Texas, Louisiana and Mississippi pipeline systems were reviewed in 2006 and no substantial changes were made to their rates.

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. 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.

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. 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.

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 treating, processing and fractionation plants, pipelines and associated facilities in connection with the gathering, treating 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 all material governmental approvals required to operate our major facilities, we are currently evaluating and updating permits for certain of our facilities specifically including those obtained in recent acquisitions. As part of the regular overall evaluation of our operations, we have implemented procedures 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 to comply with changing environmental laws and regulations and to minimize costs.

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, treating or processing and for NGL fractionation, transportation or 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 our South Louisiana Processing Assets from El Paso in November 2005. One of the acquired locations, the Cow Island Gas Processing Facility, has a known active remediation project for benzene contaminated groundwater. The cause of contamination was attributed to a leaking natural gas condensate storage tank. The site investigation and active remediation being conducted at this location is under the guidance of the Louisiana Department of Environmental Quality (LDEQ) based on the Risk-Evaluation and Corrective Action Plan Program (RECAP) rules. In addition, we are working with both the LDEQ and the Louisiana State University, Louisiana Water Resources Research Institute, on the development and implementation of a new remediation technology that will drastically reduce the remediation time as well as the costs associated with such remediation projects. The estimated remediation costs are expected to be approximately $0.5 million. Since this remediation project is a result of previous owners' operation and the actual contamination occurred prior to our ownership, these costs were accrued as part of the purchase price.

We acquired LIG Pipeline Company, and its subsidiaries, on April 1, 2004 from American Electric Power Company (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 associated with this site.

We acquired assets from Duke Energy Field Services, L.P. (DEFS) in June 2003 that have environmental contamination, including a gas plant in Montgomery County near Conroe, Texas. At Conroe, 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. Under the purchase and sale agreement, DEFS retained the liability for cleanup of the Conroe site. 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. We do not expect to incur any material liability associated with this site.

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 gathering, treating and processing of natural gas, fractionation and storage of NGLs, our facilities therefor 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 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.

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 95,400 square feet of space at our executive offices in Dallas, Texas under a lease expiring in June 2014 and approximately 16,000 square feet of office space for our south Louisiana operations in Houston, Texas with lease terms expiring in January 2013.

Employees

As of December 31, 2006, we (through our Operating Partnership) employed approximately 610 full-time employees. Approximately 287 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 1A. ***Risk Factors***

The following risk factors and all other information contained in this report should be considered carefully when evaluating us. These risk factors could affect our actual results. Other risks and uncertainties, in addition to those that are described below, may also impair our business operations. If any of the following risks occurs, our business, financial condition or results of operations could be affected materially and adversely. In that case, we may be unable to make distributions to our unitholders and the trading price of our common units could decline. These risk factors should be read in conjunction with the other detailed information concerning us set forth in our accompanying financial statements and notes and contained in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" included herein.

Acquisitions typically increase our debt and subject us to other substantial risks, which could adversely affect our results of operations.

Our future financial performance will depend, in part, on our ability to make acquisitions of assets and businesses at attractive prices. From time to time, we will evaluate and seek to acquire assets or businesses that we believe complement our existing business and related assets. We may acquire assets or businesses that we plan to use in a manner materially different from their prior owner's use. Any acquisition involves potential risks, including:

- the inability to integrate the operations of recently acquired businesses or assets;
- the diversion of management's attention from other business concerns;
- the loss of customers or key employees from the acquired businesses;
- a significant increase in our indebtedness; and
- potential environmental or regulatory liabilities and title problems.

Management's assessment of these risks is necessarily inexact and may not reveal or resolve all existing or potential problems associated with an acquisition. Realization of any of these risks could adversely affect our operations and cash flows. If we consummate any future acquisition, our capitalization and results of operations may change significantly, and you will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources.

We continue to consider large acquisition candidates and transactions. The integration, financial and other risks discussed above will be amplified if the size of our future acquisitions increases.

Our acquisition strategy is based, in part, on our expectation of ongoing divestitures of gas processing and transportation assets by large industry participants. A material decrease in such divestitures will limit our opportunities for future acquisitions and could adversely affect our growth plans.

If our assumptions used in making the acquisition of the Barnett Shale systems and facilities from Chief Holdings LLC are inaccurate, our future financial performance may be limited.

We acquired certain natural gas gathering pipeline systems and related facilities in the Barnett Shale from Chief Holdings LLC in June 2006. This acquisition was made based on our understanding of future drilling plans by Devon Energy Corporation, which acquired Chief's producing assets and acreage previously owned by Chief that is dedicated to the acquired systems. In addition, we assumed in our analysis the continued drilling success by other producers that own acreage dedicated to those systems, production success on acreage not dedicated to the systems and that we will be able to tie a certain portion of that new production into the systems. Production currently flowing through the systems is very small relative to the quantities we have assumed will be developed in the next few years. If our assumptions are inaccurate, the drilling plans of the producers are delayed, the producers are not successful in completing their wells or we are not successful in our commercial efforts to tie in gas from undedicated acreage, then our anticipated results from the acquisition from Chief of these assets could be significantly negatively impacted. In addition, the failure to successfully integrate these assets with our existing business and operations in a timely manner may have a material adverse effect on our business, financial condition, results of operations and cash flows.

We are vulnerable to operational, regulatory and other risks associated with south Louisiana and the Gulf of Mexico, including the effects of adverse weather conditions such as hurricanes, because we have a significant portion of our assets located in south Louisiana.

Our operations and revenues will be significantly impacted by conditions in south Louisiana because we have a significant portion of our assets located in south Louisiana. This concentration of activity make us more vulnerable than many of our competitors to the risks associated with Louisiana and the Gulf of Mexico, including:

- adverse weather conditions, including hurricanes and tropical storms;
- delays or decreases in production, the availability of equipment, facilities or services; and
- changes in the regulatory environment.

Because a significant portion of our operations could experience the same condition at the same time, these conditions could have a relatively greater impact on our results of operations than they might have on other midstream companies who have operations in a more diversified geographic area.

In addition, our operations in South Louisiana are dependent upon continued conventional and deep shelf drilling in the Gulf of Mexico. The deep shelf in the Gulf of Mexico is an area that has had limited historical drilling activity. This is due, in part, to its geological complexity and depth. Deep shelf development is more expensive and inherently more risky than conventional shelf drilling. A decline in the level of deep shelf drilling in the Gulf of Mexico could have an adverse effect on our financial condition and results of operations.

Our profitability is dependent upon prices and market demand for natural gas and NGLs, which are beyond our control and have been volatile.

We are subject to significant risks due to fluctuations in commodity prices. These risks are based upon three components of our business: (1) we purchase certain volumes of natural gas at a price that is a percentage of a relevant index; (2) certain processing contracts for our Gregory system and our Plaquemine and Gibson processing plants expose us to natural gas and NGL commodity price risks; and (3) part of our fees from our Conroe and Seminole gas plants as well as those acquired in the El Paso acquisition are based on a portion of the NGLs produced, and, therefore, is subject to commodity price risks.

The margins we realize from purchasing and selling a portion of the natural gas that we transport through our pipeline systems decrease in periods of low natural gas prices because our gross margins related to such purchases are based on a percentage of the index price. For the years ended December 31, 2005 and 2006, we purchased approximately 7.5% and 5.9%, respectively, of our gas at a percentage of relevant index. Accordingly, a decline in the price of natural gas could have an adverse impact on our results of operations.

A portion of our profitability is affected by the relationship between natural gas and NGL prices. For a component of our Gregory system and our Plaquemine plant and Gibson plant volumes, we purchase natural gas, process natural gas and extract NGLs, and then sell the processed natural gas and NGLs. A portion of our profits from the plants acquired in the El Paso acquisition is dependent on NGL prices and elections by us and the producers. In cases where we process gas for producers when they have the ability to decide whether to process their gas, we may elect to receive a processing fee or we may retain and sell the NGLs and keep the producer whole on its sale of natural gas. Since we extract energy content, which we measure in Btus, from the gas stream in the form of the liquids or consume it as fuel during processing, we reduce the Btu content of the natural gas. Accordingly, our margins under these arrangements can be negatively affected in periods in which the value of natural gas is high relative to the value of NGLs.

In the past, the prices of natural gas and NGLs have been extremely volatile and we expect this volatility to continue. For example, in 2005, the NYMEX settlement price for natural gas for the prompt month contract ranged from a high of $13.91 per MMBtu to a low of $6.12 per MMBtu. In 2006, the same index ranged from $11.43 per

MMBtu to $4.20 per MMBtu. A composite of the OPIS Mt. Belvieu monthly average liquids price based upon our average liquids composition in 2005 ranged from a high of approximately $1.16 per gallon to a low of approximately $0.80 per gallon. In 2006, the same composite ranged from approximately $1.20 per gallon to approximately $0.90 per gallon.

We may not be successful in balancing our purchases and sales. In addition, a producer could fail to deliver contracted volumes or deliver in excess of contracted volumes, or a consumer could purchase less than contracted volumes. Any of these actions could cause our purchases and sales not to be balanced. If our purchases and sales are not balanced, we will face increased exposure to commodity price risks and could have increased volatility in our operating income.

The markets and prices for residue gas and NGLs depend upon factors beyond our control. These factors include demand for oil, natural gas and NGLs, which fluctuate with changes in market and economic conditions and other factors, including:

- the impact of weather on the demand for oil and natural gas;
- the level of domestic oil and natural gas production;
- the level of domestic industrial and manufacturing activity;
- the availability of imported oil and natural gas;
- actions taken by foreign oil and gas producing nations;
- the availability of local, intrastate and interstate transportation systems;
- the availability and marketing of competitive fuels;
- the impact of energy conservation efforts; and
- the extent of governmental regulation and taxation.

We must continually compete for natural gas supplies, and any decrease in our supplies of natural gas could adversely affect our financial condition and results of operations.

If we are unable to maintain or increase the throughput on our systems by accessing new natural gas supplies to offset the natural decline in reserves, our business and financial results could be materially, adversely affected. In addition, our future growth will depend, in part, upon whether we can contract for additional supplies at a greater rate than the rate of natural decline in our currently connected supplies.

In order to maintain or increase throughput levels in our natural gas gathering systems and asset utilization rates at our treating and processing plants, we must continually contract for new natural gas supplies. We may not be able to obtain additional contracts for natural gas supplies. The primary factors affecting our ability to connect new wells to our gathering facilities include our success in contracting for existing natural gas supplies that are not committed to other systems and the level of drilling activity near our gathering systems. Fluctuations in energy prices can greatly affect production rates and investments by third parties in the development of new oil and natural gas reserves. Drilling activity generally decreases as oil and natural gas prices decrease. Tax policy changes could have a negative impact on drilling activity, reducing supplies of natural gas available to our systems. We have no control over producers and depend on them to maintain sufficient levels of drilling activity. A material decrease in natural gas production or in the level of drilling activity in our principal geographic areas for a prolonged period, as a result of depressed commodity prices or otherwise, likely would have a material adverse effect on our results of operations and financial position.

A substantial portion of our assets is connected to natural gas reserves that will decline over time, and the cash flows associated with those assets will decline accordingly.

A substantial portion of our assets, including our gathering systems and our treating plants, is dedicated to certain natural gas reserves and wells for which the production will naturally decline over time. Accordingly, our cash flows associated with these assets will also decline. If we are unable to access new supplies of natural gas either by connecting additional reserves to our existing assets or by constructing or acquiring new assets that have access to additional natural gas reserves, our cash flows may decline.

Growing our business by constructing new pipelines and processing and treating facilities subjects us to construction risks, risks that natural gas supplies will not be available upon completion of the facilities and risks of construction delay and additional costs due to obtaining rights-of-way.

One of the ways we intend to grow our business is through the construction of additions to our existing gathering systems and construction of new pipelines and gathering, processing and treating facilities. The construction of pipelines and gathering, processing and treating facilities requires the expenditure of significant amounts of capital, which may exceed our expectations. Generally, we may have only limited natural gas supplies committed to these facilities prior to their construction. Moreover, we may construct facilities to capture anticipated future growth in production in a region in which anticipated production growth does not materialize. We may also rely on estimates of proved reserves in our decision to construct new pipelines and facilities, which may prove to be inaccurate because there are numerous uncertainties inherent in estimating quantities of proved reserves. As a result, new facilities may not be able to attract enough natural gas to achieve our expected investment return, which could adversely affect our results of operations and financial condition. In addition, we face the risks of construction delay and additional costs due to obtaining rights-of-way.

We have limited control over the development of certain assets because we are not the operator.

As the owner of non-operating interests in the Seminole processing plant, we do not have the right to direct or control the operation of the plant. As a result, the success of the activities conducted at this plant, which is operated by a third party, may be affected by factors outside of our control. The failure of the third-party operator to make decisions, perform its services, discharge its obligations, deal with regulatory agencies or comply with laws, rules and regulations affecting this plant, including environmental laws and regulations, in a proper manner could result in material adverse consequences to our interest and adversely affect our results of operations.

We expect to encounter significant competition in any new geographic areas into which we seek to expand and our ability to enter such markets may be limited.

As we expand our operations into new geographic areas, we expect to encounter significant competition for natural gas supplies and markets. Competitors in these new markets will include companies larger than us, which have both lower capital costs and greater geographic coverage, as well as smaller companies, which have lower total cost structures. As a result, we may not be able to successfully develop acquired assets and markets located in new geographic areas and our results of operations could be adversely affected.

We are exposed to the credit risk of our customers and counterparties, and a general increase in the nonpayment and nonperformance by our customers could have an adverse effect on our financial condition and results of operations.

Risks of nonpayment and nonperformance by our customers are a major concern in our business. We are subject to risks of loss resulting from nonpayment or nonperformance by our customers. Any increase in the nonpayment and nonperformance by our customers could adversely affect our results of operations.

We may not be able to retain existing customers or acquire new customers, which would reduce our revenues and limit our future profitability.

The renewal or replacement of existing contracts with our customers at rates sufficient to maintain current revenues and cash flows depends on a number of factors beyond our control, including competition from other pipelines, and the price of, and demand for, natural gas in the markets we serve.

For the year ended December 31, 2006, approximately 71% of our sales of gas which were transported using our physical facilities were to industrial end-users and utilities. As a consequence of the increase in competition in the industry and volatility of natural gas prices, end-users and utilities are reluctant to enter into long-term purchase contracts. Many end-users purchase natural gas from more than one natural gas company and have the ability to change providers at any time. Some of these end-users also have the ability to switch between gas and alternate fuels in response to relative price fluctuations in the market. Because there are numerous companies of greatly varying size and financial capacity that compete with us in the marketing of natural gas, we often compete in the end-user and utilities markets primarily on the basis of price. The inability of our management to renew or replace our current contracts as they expire and to respond appropriately to changing market conditions could have a negative effect on our profitability.

We depend on certain key customers, and the loss of any of our key customers could adversely affect our financial results.

We derive a significant portion of our revenues from contracts with key customers. To the extent that these and other customers may reduce volumes of natural gas purchased under existing contracts, we would be adversely affected unless we were able to make comparably profitable arrangements with other customers. Agreements with key customers provide for minimum volumes of natural gas that each customer must purchase until the expiration of the term of the applicable agreement, subject to certain force majeure provisions. Customers may default on their obligations to purchase the minimum volumes required under the applicable agreements.

Our business involves many hazards and operational risks, some of which may not be fully covered by insurance.

Our operations are subject to the many hazards inherent in the gathering, compressing, treating and processing of natural gas and storage of residue gas, including:

- damage to pipelines, related equipment and surrounding properties caused by hurricanes, floods, fires and other natural disasters and acts of terrorism;
- inadvertent damage from construction and farm equipment;
- leaks of natural gas, NGLs and other hydrocarbons; and
- fires and explosions.

These risks could result in substantial losses due to personal injury and/or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage and may result in curtailment or suspension of our related operations. Our operations are concentrated in Texas, Louisiana and the Mississippi Gulf Coast, and a natural disaster or other hazard affecting this region could have a material adverse effect on our operations. We are not fully insured against all risks incident to our business. In accordance with typical industry practice, we do not have any property insurance on any of our underground pipeline systems that would cover damage to the pipelines. We are not insured against all environmental accidents that might occur, other than those considered to be sudden and accidental. Our business interruption insurance covers only our Gregory processing plant. If a significant accident or event occurs that is not fully insured, it could adversely affect our operations and financial condition.

The threat of terrorist attacks has resulted in increased costs, and future war or risk of war may adversely impact our results of operations and our ability to raise capital.

Terrorist attacks or the threat of terrorist attacks cause instability in the global financial markets and other industries, including the energy industry. Uncertainty surrounding retaliatory military strikes or a sustained military campaign may affect our operations in unpredictable ways, including disruptions of fuel supplies and markets, and the possibility that infrastructure facilities, including pipelines, production facilities, and transmission and distribution facilities, could be direct targets, or indirect casualties, of an act of terror. Instability in the financial markets as a result of terrorism, the war in Iraq or future developments could also affect our ability to raise capital.

Changes in the insurance markets attributable to the threat of terrorist attacks have made certain types of insurance more difficult for us to obtain. Our insurance policies now generally exclude acts of terrorism. Such insurance is not available at what we believe to be acceptable pricing levels. A lower level of economic activity could also result in a decline in energy consumption, which could adversely affect our revenues or restrict our future growth.

Federal, state or local regulatory measures could adversely affect our business.

While the FERC, generally does not regulate our operations, it influences certain aspects of our business and the market for our products. The rates, terms and conditions of service under which we transport natural gas in our pipeline systems in interstate commerce are subject to FERC regulation under the Section 311 of the NGPA. 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. Should FERC or any of these state agencies determine that our rates for Section 311 transportation service or intrastate transportation service should be lowered, our business could be adversely affected.

Our natural gas gathering activities generally are exempt from FERC regulation under the NGA. 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. 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. 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.

Other state and local regulations also affect our business. We are subject to ratable take and common purchaser statutes in the states where we operate. 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 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. Federal law leaves any economic regulation of natural gas gathering to the states, and some of the states in which we operate have adopted complaint-based or other limited economic regulation of natural gas gathering activities. States in which we operate that have adopted some form of complaint-based regulation, like Oklahoma and Texas, generally allow 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.

The states in which we conduct operations administer federal pipeline safety standards under the Pipeline Safety Act of 1968. The “rural gathering exemption” under the Natural Gas Pipeline Safety Act of 1968 presently exempts substantial portions of our gathering facilities from jurisdiction under that statute, including those portions located outside of cities, towns, or any area designated as residential or commercial, such as a subdivision or shopping center. The “rural gathering exemption,” however, may be restricted in the future, and it does not apply to our natural gas transmission pipelines. In response to recent pipeline accidents in other parts of the country, Congress and the Department of Transportation, or DOT, have passed or are considering heightened pipeline safety requirements.

Compliance with pipeline integrity regulations issued by the TRRC, or those issued by the United States Department of Transportation in December of 2003 could result in substantial expenditures for testing, repairs and replacement. TRRC regulations require periodic testing of all intrastate pipelines meeting certain size and location requirements. Our costs relating to compliance with the required testing under the TRRC regulations were approximately $1.1 million, $0.3 million and $1.9 million for the years ended December 31, 2006, 2005 and 2004, respectively. We expect the costs for compliance with TRRC and DOT regulations to be $5.6 million during 2007. If our pipelines fail to meet the safety standards mandated by the TRRC or the DOT regulations, then we may be required to repair or replace sections of such pipelines, the cost of which cannot be estimated at this time.

Our business involves hazardous substances and may be adversely affected by environmental regulation.

Many of the operations and activities of our gathering systems, plants and other facilities, including our South Louisiana Processing business, are subject to significant federal, state and local environmental laws and regulations. These laws and regulations impose obligations related to air emissions and discharge of pollutants from our facilities and the cleanup of hazardous substances and other wastes that may have been released at properties currently or previously owned or operated by us or locations to which we have sent wastes for treatment or disposal. Various governmental authorities have the power to enforce compliance with these regulations and the permits issued under them, and violators are subject to administrative, civil and criminal penalties, including civil fines, injunctions or both. Strict, joint and several liability may be incurred under these laws and regulations for the remediation of contaminated areas. Private parties, including the owners of properties through which our gathering systems pass, may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage.

There is inherent risk of the incurrence of significant environmental costs and liabilities in our business due to our handling of natural gas and other petroleum products, air emissions related to our operations, historical industry operations, waste disposal practices and the prior use of natural gas flow meters containing mercury. In addition, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase our compliance costs and the cost of any remediation that may become necessary. We may incur material environmental costs and liabilities. Furthermore, our insurance may not provide sufficient coverage in the event an environmental claim is made against us.

Our business may be adversely affected by increased costs due to stricter pollution control requirements or liabilities resulting from non-compliance with required operating or other regulatory permits. New environmental regulations might adversely affect our products and activities, including processing, storage and transportation, as well as waste management and air emissions. Federal and state agencies could also impose additional safety requirements, any of which could affect our profitability.

Our use of derivative financial instruments has in the past and could in the future result in financial losses or reduce our income.

We use over-the-counter price and basis swaps with other natural gas merchants and financial institutions, and we use futures and option contracts traded on the New York Mercantile Exchange. Use of these instruments is intended to reduce our exposure to short-term volatility in commodity prices. We could incur financial losses or fail to recognize the full value of a market opportunity as a result of volatility in the market values of the underlying commodities or if one of our counterparties fails to perform under a contract.

Due to our lack of asset diversification, adverse developments in our gathering, transmission, treating, processing and producer services businesses would materially impact our financial condition.

We rely exclusively on the revenues generated from our gathering, transmission, treating, processing and producer services businesses, and as a result our financial condition depends upon prices of, and continued demand for, natural gas and NGLs. Due to our lack of asset diversification, an adverse development in one of these businesses would have a significantly greater impact on our financial condition and results of operations than if we maintained more diverse assets.

Our success depends on key members of our management, the loss or replacement of whom could disrupt our business operations.

We depend on the continued employment and performance of the officers of the general partner of our general partner and key operational personnel. The general partner of our general partner has entered into employment agreements with each of its executive officers. If any of these officers or other key personnel resign or become unable to continue in their present roles and are not adequately replaced, our business operations could be materially adversely affected. We do not maintain any “key man” life insurance for any officers.

Item 1B. ***Unresolved Staff Comments***

We do not have any unresolved staff comments.

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 processing plants are located on land that we lease or own in fee. Our treating facilities are generally located on sites provided by producers or other parties.

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 or defects. We believe that none of such encumbrances or defects 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. These include litigation on disputes related to contracts, property rights, use or damage and personal injury. We do not believe that any pending or threatened claim or dispute is material to our financial results or our operations. 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.

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, 2006.

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 Global Select Market under the symbol "XTEX". On February 16, 2007, the market price for the common units was $37.36 per unit and there were approximately 10,500 record holders and beneficial owners (held in street name) of our common units, one record holder of our 4,668,000 subordinated units and nine record holders of our 12,829,650 senior subordinated C units. There is no established public trading market for our subordinated units or our senior subordinated C units.

The following table shows the high and low sales prices per common unit, as reported by the NASDAQ Global Select Market, for the periods indicated.

	Common Unit Price Range(a)		Cash Distribution
	High	Low	Paid per Unit(a)
2006:			
Quarter Ended December 31	$ 40.00	$ 35.11	$ 0.56
Quarter Ended September 30	38.17	34.83	0.55
Quarter Ended June 30	38.88	33.23	0.54
Quarter Ended March 31	37.81	33.52	0.53
2005:			
Quarter Ended December 31	$ 40.42	$ 32.04	$ 0.51
Quarter Ended September 30	45.50	37.20	0.49
Quarter Ended June 30	39.58	32.00	0.47
Quarter Ended March 31	37.25	31.55	0.46

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

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."

Conversion of Subordinated 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.

If the Partnership meets the applicable financial tests in the partnership agreement for the three consecutive four-quarter periods ended on December 31, 2005 or December 31, 2006, up to 4,666,000 of the subordinated units may be converted into common units prior to December 31, 2007. The Partnership met the financial tests for three consecutive four-quarter periods ended December 31, 2005, and 2,333,000 subordinated units converted to common units upon the payment of the fourth quarter 2005 distribution on February 15, 2006. The Partnership also met these tests for the three consecutive four-quarter periods ended December 31, 2006. As a result, an additional 2,333,000 subordinated units converted to common units upon the payment of the fourth quarter 2006 distribution on February 15, 2007.

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 Plan (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	1,262,660(1)(2)	$ 25.70(3)	844,591

(1) Our general partner has adopted and maintains a long-term incentive plan for our officers, employees and directors. See Item 11. "Executive Compensation — Compensation Discussion and Analysis." The plan, as amended, provides for issuance of a total of 2,600,000 common unit options and restricted units.

(2) The number of securities includes 336,504 restricted units that have been granted under our long-term incentive plan that have not vested.

(3) The exercise prices for outstanding options under the plan as of December 31, 2006 range from $10.00 to $37.05 per unit.

Item 6. ***Selected Financial Data***

The following table sets forth selected historical financial and operating data of Crosstex Energy, L.P. 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. In addition, our summary historical financial and operating data include the results of operations of the Vanderbilt system beginning in December 2002, the Mississippi pipeline system and Seminole processing plant beginning in June 2003, the LIG assets beginning in April 2004, the Graco assets beginning January 2005, the Cardinal assets beginning May 2005, the South Louisiana Processing Assets beginning November 1, 2005, the Hanover assets beginning January 2006, the NTP beginning April 2006 and the Chief midstream assets beginning June 29, 2006 and other smaller acquisitions completed in 2006.

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

	Crosstex Energy, L.P.				
	Year Ended December 31, 2006	Year Ended December 31, 2005	Year Ended December 31, 2004	Year Ended December 31, 2003	Year Ended December 31, 2002
	(Dollars in thousands, except per unit amounts)				
Statement of Operations Data:					
Revenues:					
Midstream	$ 3,073,069	$ 2,982,874	$ 1,948,021	$ 989,697	$ 437,432
Treating	66,225	48,606	30,755	23,966	14,817
Profit on energy trading activities	2,510	1,568	2,228	2,266	1,791
Total revenues	3,141,804	3,033,048	1,981,004	1,015,929	454,040
Operating costs and expenses:					
Midstream purchased gas	2,859,815	2,860,823	1,861,204	946,412	414,244
Treating purchased gas	9,463	9,706	5,274	7,568	5,767
Operating expenses	100,991	56,736	38,340	19,814	11,409
General and administrative(1)	45,694	32,697	20,866	10,067	7,554
Impairments	—	—	—	—	4,175
(Gain) loss on derivatives	(1,599)	9,968	(279)	361	134
Gain on sale of property	(2,108)	(8,138)	(12)	—	—
Depreciation and amortization	82,731	36,024	23,034	13,268	7,745
Total operating costs and expenses	3,094,987	2,997,816	1,948,427	997,490	451,028
Operating income	46,817	35,232	32,577	18,439	3,012
Other income (expense):					
Interest expense, net	(51,427)	(15,767)	(9,220)	(3,392)	(2,717)
Other income (expense)	183	392	798	179	49
Total other income (expense)	(51,244)	(15,375)	(8,422)	(3,213)	(2,668)
Income and (loss) before minority interest and taxes	(4,427)	19,857	24,155	15,226	344
Minority interest	(231)	(441)	(289)	—	—
Federal income taxes	(222)	(216)	(162)	—	—

	Crosstex Energy, L.P. Year Ended December 31, 2006	Year Ended December 31, 2005	Year Ended December 31, 2004	Year Ended December 31, 2003	Year Ended December 31, 2002
	(Dollars in thousands, except per unit amounts)				
Income (loss) before cumulative effect of change in accounting principle	(4,880)	19,200	23,704	15,226	344
Cumulative effect of change in accounting principle	689	—	—	—	—
Net income (loss)	$ (4,191)	$ 19,200	$ 23,704	$ 15,226	$ 344
Net income (loss) per limited partner unit-basic(2)	$ (0.78)	$ 0.56	$ 0.98	$ 0.89	$ 0.02
Net income (loss) per limited partner unit-diluted(2)	$ (0.78)	$ 0.51	$ 0.95	$ 0.88	$ 0.02
Distributions per limited partner unit(3)	$ 2.18	$ 1.93	$ 1.70	$ 1.25	$ 0.028
Balance Sheet Data (end of period):					
Working capital deficit	$ (79,936)	$ (11,681)	$ (34,724)	$ (4,572)	$ (10,330)
Property and equipment, net	1,105,813	667,142	324,730	203,909	109,948
Total assets	2,194,474	1,425,158	586,771	366,050	233,185
Long-term debt	987,130	522,650	148,700	60,750	22,550
Partners' equity	711,877	401,285	144,050	154,610	88,158
Cash Flow Data:					
Net cash flow provided by (used in):					
Operating activities	$ 113,010	$ 14,010	$ 48,103	$ 46,460	$ (5,672)
Investing activities	(885,825)	(615,017)	(124,371)	(110,289)	(33,240)
Financing activities	772,234	596,615	81,899	62,687	39,868
Other Financial Data:					
Midstream gross margin	$ 215,764	$ 123,619	$ 89,045	$ 45,551	$ 24,979
Treating gross margin	56,762	38,900	25,481	16,398	9,050
Total gross margin(4)	$ 272,526	$ 162,519	$ 114,526	$ 61,949	$ 34,029
Operating Data:					
Pipeline throughput (MMBtu/d)	1,450,000	1,222,000	1,289,000	626,000	392,000
Natural gas processed (MMBtu/d)(5)	1,938,000	1,825,000	425,000	132,000	86,000
Producer Services (MMBtu/d)	138,000	175,000	210,000	259,000	230,000

(1) For the year ended December 31, 2003, the amount for which our 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.

(2) 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.

(3) Distributions include fourth quarter 2006 distributions of $0.56 per unit paid in February 2007; fourth quarter 2005 distributions of $0.51 per unit paid in February 2006; fourth quarter 2004 distributions of $0.45 per unit paid in February 2005; fourth quarter of 2003 distributions of $0.375 per unit paid in February 2004; and fourth quarter of 2002 distributions of $0.028 per unit paid in February 2003.

(4) Gross margin is defined as revenue, including treating fee revenues and profit on energy trading activities, less related cost of purchased gas.

(5) For the year ended 2005, processed volumes include a daily average for the south Louisiana processing plants for November 2005 and December 2005, the two-month period these assets were operated by us.

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 on July 12, 2002 to indirectly acquire substantially all of the assets, liabilities and operations of our predecessor, Crosstex Energy Services, Ltd. We have two industry segments, Midstream and Treating, with a geographic focus along the Texas Gulf Coast, in the north Texas Barnett Shale area, and in Louisiana and Mississippi. Our Midstream division focuses on the gathering, processing, transmission and marketing of natural gas and NGLs, as well as providing certain producer services, while our Treating division focuses on the removal of contaminants from natural gas and NGLs to meet pipeline quality specifications. For the year ended December 31, 2006, 79% of our gross margin was generated in the Midstream division with the balance in the Treating division. We manage our business by focusing on gross margin because our business is generally to purchase and resell gas for a margin, or to gather, process, transport, market or treat gas or NGLs 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. In addition, we receive certain fees for processing based on a percentage of the liquids produced and enter into hedge contracts for our expected share of the liquids produced to protect our margins from changes in liquids prices. As explained under "Commodity Price Risk" below, we enter into financial instruments to reduce volatility in our gross margin due to price fluctuations.

During the past five years 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, 2002 through December 31, 2006, we have invested over $1.7 billion 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 Midstream segment margins are determined primarily by the volumes of natural gas gathered, transported, purchased and sold through our pipeline systems, processed at our processing facilities, and the volumes of NGLs handled at our fractionation facilities. Our Treating segment margins are largely a function of the number and size of treating plants in operation and fees earned for removing impurities and from NGLs 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 and fractionating and marketing the recovered NGLs;
- treating natural gas at our treating plants;
- recovering carbon dioxide and NGLs at a non-operated processing plant; and
- providing off-system marketing services for producers.

The bulk of our operating profits has historically been derived from the margins we realize for gathering and transporting natural gas through our pipeline systems. Generally, we buy gas from a producer, plant 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 generally 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.

Processing and fractionation revenues are largely fee based. Our processing fees are largely based on either a percentage of the liquids volume recovered, or a fixed fee per unit processed. Fractionation and marketing fees are generally fixed fee per unit of products.

We generate treating revenues under three arrangements:

- a volumetric fee based on the amount of gas treated, which accounted for approximately 48% and 51% of the operating income in our Treating division for the years ended December 31, 2006 and 2005, respectively;
- a fixed fee for operating the plant for a certain period, which accounted for approximately 32% and 38% of the operating income in our Treating division for the years ended December 31, 2006 and 2005, respectively; or
- a fee arrangement in which the producer operates the plant, which accounted for approximately 20% and 11% of the operating income in our Treating division for the years ended December 31, 2006 and 2005, 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 facility.

Our general and administrative expenses are dictated by the terms of our partnership agreement. 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 business 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.

Acquisitions

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 2004 were the acquisition of the Chief midstream assets, the South Louisiana Processing Assets and the LIG Pipeline Company and its subsidiaries. We also purchased treating assets totaling $16.0 million and $58.0 million during 2005 and 2006, respectively.

On June 29, 2006, we acquired the natural gas gathering pipeline systems and related facilities of Chief in the Barnett Shale for $475.3 million. The acquired systems consist of approximately 250 miles of existing pipeline with up to an additional 400 miles of planned pipelines, located in Parker, Tarrant, Denton, Palo Pinto, Erath, Hood, Somervell, Hill and Johnson counties, all of which are located in Texas. The acquired assets also include a 125 MMcf/d carbon dioxide treating plant and compression facilities with 26,000 horsepower. At closing, approximately 160,000 net acres previously owned by Chief and acquired by Devon simultaneously with our acquisition, as well as 60,000 net acres owned by other producers, were dedicated to the systems. Immediately following the closing of the Chief acquisition, we began expanding our north Texas pipeline gathering system. As of December 31, 2006, we had installed approximately 49 miles of gathering pipeline and connected 85 new wells to our gathering system, 46 of which are owned or controlled by Devon and 39 of which are owned or controlled by other producers. In addition to expanding our gathering system, we had installed 4,400 horsepower of additional compression to handle the increased volumes. We also installed a new 55,000 Mcf/d cryogenic processing plant and added inlet refrigeration to an existing 30,000 Mcf/d plant in order to remove hydrocarbon liquids from growing gas streams. We have increased total throughput on this gathering system from approximately 115 MMcf/d at the time of acquisition to 230 MMcf/d for the month of December 2006.

On February 1, 2006, we acquired 48 amine treating plants from a subsidiary of Hanover Compression Company for $51.7 million.

On October 3, 2006, the Partnership acquired the amine-treating business of Cardinal Gas Solutions Limited Partnership for $6.3 million. The acquisition added 10 dew point control plants and seven amine-treating plants to our plant portfolio.

On November 1, 2005, we acquired El Paso's processing and liquids business in south Louisiana for $481.0 million. The assets acquired include 2.3 Bcf/d of processing capacity, 66,000 barrels per day of fractionation capacity, 2.4 million barrels of underground storage and 400 miles of liquids transport lines. The primary facilities and other assets we acquired consist of: (1) the Eunice processing plant and fractionation facility; (2) the Pelican processing plant; (3) the Sabine Pass processing plant; (4) a 23.85% interest in the Blue Water gas processing plant; (5) the Riverside fractionator and loading facility; (6) the Cajun Sibon pipeline; and (7) the Napoleonville NGL storage facility. In May 2006, we acquired an additional 35.42% interest in the Blue Water gas processing plant for $16.5 million and became the operator of the plant.

On January 2, 2005, we acquired all of the assets of Graco Operations for $9.3 million. Graco's assets consisted of 26 treating plants and associated inventory. On May 1, 2005 we acquired all of the assets of Cardinal Gas Services for $6.7 million. Cardinal's assets consisted of nine gas treating plants, 19 dew point control plants and equipment inventory.

In April 2004, we acquired LIG Pipeline Company and its subsidiaries 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 two operating processing plants, with total processing capacity of approximately 335,000 MMBtu/d. 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 which provides access to additional system supply.

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 crude oil, NGL products and natural gas.

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, 2006.

	Year Ended December 31, 2006			
	Gas Purchased		Gas Sold	
Asset or Business	Fixed Amount to Index	Percentage of Index	Fixed Amount to Index	Percentage of Index
	(In thousands of MMBtu's)			
LIG system	141,635	6,384	148,019	—
South Texas system(1)	148,111	15,134	148,186	—
North Texas system	28,177	—	28,177	—
Other assets and activities(1)	78,921	3,205	73,105	—

(1) Gas sold is less than gas purchased due to production of NGLs on some of the assets included in the south Texas system and other assets.

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 $1.3 million on an annual basis (before consideration of our hedge positions). As of December 31, 2006, we have hedged approximately 78% of our exposure to such fluctuations in natural gas prices in 2007 and approximately 70 % of our exposure to such fluctuations for the first quarter of 2008. We expect to continue to hedge our exposure to gas prices when market opportunities appear attractive.

We processed approximately 70.4% of our volume during 2006 at Eunice, Pelican, Sabine and Blue Water under "percent of proceeds" contracts, under which we receive as a fee a portion of the liquids produced, and 29.6% of our volume as fixed fee per unit processed. Under percent of proceeds contracts, we are exposed to changes in the prices of NGLs. For the years 2006 and 2007, we have purchased puts or entered into forward sales covering all of our anticipated minimum share of NGLs production.

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.

For the year ended December 31, 2006, we purchased a small amount (approximately 5.1%) 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 94.9% 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.

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 $0.68 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 2006, our share of NGLs totaled approximately 5.4 million gallons at an average price of $1.03 per gallon. We have executed forward sales on approximately 81% of our anticipated 2007 share of NGLs and approximately 40% of our share of NGLs for the first quarter of 2008.

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, 2006	2005	2004
		(Dollars in millions)	
Midstream revenues	$ 3,073.1	$ 2,982.9	$ 1,948.0
Midstream purchased gas	(2,859.8)	(2,860.8)	(1,861.2)
Profits on energy trading activities	2.5	1.6	2.2
Midstream gross margin	215.8	123.7	89.0
Treating revenues	66.2	48.6	30.8
Treating purchased gas	(9.5)	(9.7)	(5.3)
Treating gross margin	56.7	38.9	25.5
Total gross margin	$ 272.5	$ 162.6	$ 114.5
Midstream Volumes (MMBtu/d):			
Gathering and transportation	1,450,000	1,222,000	1,289,000
Processing	1,938,000	1,825,000	425,000
Producer services	138,000	175,000	210,000
Treating Plants in Operation at Year-end	160	112	74

Year Ended December 31, 2006 Compared to Year Ended December 31, 2005

Gross Margin and Profit on Energy Trading Activities. Midstream gross margin was $215.8 million for the year ended December 31, 2006 compared to $123.7 million for the year ended December 31, 2005, an increase of $92.1 million, or 75%. This increase was primarily due to acquisitions, increased system throughput and a favorable processing environment for natural gas and natural gas liquids.

The South Louisiana Processing Assets acquired in November 2005 contributed $56.1 million to Midstream gross margin growth in 2006. This amount was driven by the three largest processing plants, Eunice, Pelican and Sabine Pass, which contributed gross margin increases of $25.1 million, $11.4 million and $9.1 million, respectively. The Riverside fractionation facility and the Blue Water plant also contributed gross margin growth to the south Louisiana operations of $5.1 million and $3.7 million, respectively. Operational improvements and volume increases on the LIG system contributed margin growth of $12.5 million during 2006. Increased processing volumes at the Gibson and Plaquemine plants due to drilling successes by producers and increased unit margins due to favorable NGL markets accounted for a $9.5 million increase in gross margin. We acquired the north Texas gathering system from Chief in June 2006. This gathering system and related facilities contributed $11.7 million of gross margin during 2006. The NTP commenced operation during the second quarter of 2006 and contributed $8.0 million in gross margin. These gains were partially offset by volume and margin declines on our southern region assets. Decreased throughput on the CCNG, Gregory and Gulf Coast systems contributed to an overall margin decrease in our southern region of $6.9 million.

The favorable processing margins we realized during 2006 at our South Louisiana Processing Assets, the Gibson plant and the Plaquemine plant may be higher than processing margins we may realize during 2007 and future periods if the NGL markets do not remain as strong as they were during 2006. As discussed above under "— *Commodity Price Risk*", we receive a processing fee as a portion of liquids processed or a percentage of the liquids recovered on a substantial portion of the gas processed through these plants. During periods when processing margins are favorable, as existed during 2006, we experience higher processing margins. We have the ability to bypass certain volumes when processing is uneconomic so we can limit our exposure to adverse processing margins but our processing margins will be lower during these periods.

In addition, we have the ability to buy gas from and to sell gas to various gas markets through our pipeline systems. During 2006 we were able to benefit from price differentials between the various gas markets by selling gas into markets with more favorable pricing thereby improving our Midstream gross margin. If these price differentials do not exist during 2007 and future periods, our Midstream gross margin may be lower.

Treating gross margin was $56.7 million for the year ended December 31, 2006 compared to $38.9 million for the year ended December 31, 2005, an increase of $17.8 million, or 46%. Treating plants in service increased from 112 plants at December 2005 to 160 plants at December 2006. The increase in the number of plants in service is primarily due to the acquisition of the amine treating assets from Hanover Compressor Company in February of 2006. New plants associated with the Hanover acquisition contributed $7.4 million in gross margin growth. The field services also acquired from Hanover contributed $1.0 million in gross margin for the year. Plant additions from inventory and expansion projects at existing plants contributed gross margin growth of $6.6 million and $0.5 million, respectively. The Seminole plant contributed $1.5 million of gross margin growth due to the recalculation of fees based on rate escalations set forth in the contract. The acquisition and installation of dew point control plants contributed an additional $0.7 million increase to gross margin.

Operating Expenses. Operating expenses were $101.0 million for the year ended December 31, 2006 compared to $56.7 million for the year ended December 31, 2005, an increase of $44.3 million, or 78%. An increase of $27.0 million in operating expenses was associated with the South Louisiana Processing Assets which were owned for a full year in 2006 and only two months in 2005. Other Midstream increases of $7.7 million were due to the commencement of operations of the NTP as well as the Chief acquisition. The growth in the number of treating plants in service increased operating expenses by $4.8 million. Engineering and other technical service support costs also increased $2.9 million due to our asset growth. The remaining increase of $1.9 million is due to increased costs on our other Midstream systems. Operating expenses included stock-based compensation expenses of $1.1 million and $0.4 million for the years ended December 31, 2006 and 2005, respectively.

General and Administrative Expenses. General and administrative expenses were $45.7 million for the year ended December 31, 2006 compared to $32.7 million for the year ended December 31, 2005, an increase of $13.0 million, or 40%. A substantial part of the increased expenses resulted from staffing related costs of $6.5 million. The staff additions associated with the requirements of the El Paso, Hanover and Chief acquisitions, as well as the commencement of the NTP operations, accounted for the majority of the $6.5 million increase. Audit, legal and other consulting fees, office rent, travel, training and other administrative expenses, which increased due to our growth, accounted for $2.7 million of the increase. General and administrative expenses included stock-based compensation expense of $7.4 million and $3.7 million for the year ended December 31, 2006 and 2005, respectively. The $3.8 million increase in stock-based compensation, determined in accordance with FAS 123R during 2006 and in accordance with APB25 in 2005, primarily relates to an increase in restricted stock and unit grants due to an increase in the pool of eligible participants.

Gain/Loss on Derivatives. We had a gain on derivatives of $1.6 million for the year ended December 31, 2006 compared to a loss of $10.0 million for the year ended December 31, 2005. The gain in 2006 includes a gain of $2.9 million on storage financial transactions (including $0.7 million of realized gain), a gain of $0.7 million associated with our basis swaps (including $0.4 million of realized gain), a gain of $1.5 million associated with derivatives for third-party on-system financial transactions (including $1.2 million of realized gains), and a gain of $0.1 million due to ineffectiveness in our hedged derivatives partially offset by a loss of $3.6 million on puts acquired in 2005 related to the acquisition of the South Louisiana Processing Assets. As of December 31, 2006, the fair value of the puts was $1.7 million. The loss in 2005 includes a $9.2 million loss on the puts related to the acquisition of the South Louisiana Processing Assets.

Gain/Loss on Sale of Property. Assets sold during the year ended December 31, 2006 generated a net gain of $2.1 million as compared to a gain of $8.1 million during the year ended December 31, 2005. The gains in 2006 and 2005 primarily related to the sale of inactive gas processing facilities acquired as part of the South Louisiana Processing Assets and as part of the LIG acquisition.

Depreciation and Amortization. Depreciation and amortization expenses were $82.7 for the year ended December 31, 2006 compared to $36.0 million for the year ended December 31, 2005, an increase of $46.7 million, or 130%. An increase of $28.7 million in depreciation expense was associated with the South Louisiana Processing Assets which were owned for a full year in 2006 and only two months in 2005. The acquisition of the north Texas gathering system from Chief, the commencement of operations of the NTP and the related developments in north Texas in 2006 increased depreciation expense by $9.6 million. The acquisition of the treating assets from Hanover in 2006 contributed an increase of $2.5 million and other new treating plants acquired and placed in service contributed an increase of $2.5 million. The remaining increase of $3.4 million was a result of various other expansion projects, including the expansion of our corporate offices and related support facilities.

Interest Expense. Interest expense was $51.4 million for the year ended December 31, 2006 compared to $15.8 million for the year ended December 31, 2005, an increase of $35.6 million. The increase relates primarily to an increase in debt outstanding as a result of acquisitions and other growth projects and higher interest rates between years (weighted average rate of 6.9% in 2006 compared to 6.3% in 2005).

Year Ended December 31, 2005 Compared to Year Ended December 31, 2004

Gross Margin and Profit on Energy Trading Activities. Midstream gross margin was $123.7 million for the year ended December 31, 2005 compared to $89.0 million for the year ended December 31, 2004, an increase of $34.7 million, or 39%. This increase was primarily due to acquisitions, volatile prices in the last half of the year and operational improvements on existing systems.

The acquisition of the South Louisiana Processing Assets contributed $14.1 million of gross margin in the fourth quarter of 2005. The acquisition of the LIG assets on April 1, 2004, contributed $6.3 million to midstream gross margin in 2005 in our first full year of ownership. In addition, the acquisition of all outside interests in Crosstex Pipeline Partners, LLP as of December 31, 2004, accounted for a gross margin increase of $1.7 million. Relatively high and volatile natural gas prices during the fourth quarter created favorable margin opportunities on several systems, offset by the negative impact on processing margins of high gas prices, as certain gas was no longer economical to process. The impact of these high and volatile gas prices on Midstream operations was a gross margin increase of $5.4 million. Operational improvements and volume increases contributed margin growth of $5.1 million on the Vanderbilt, Denton County and Arkoma systems. In addition, the Gregory Gathering system had a margin increase of $1.7 million primarily due to two measurement disputes which were settled during the year.

Treating gross margin was $38.9 million for the year ended December 31, 2005 compared to $25.5 million in the same period in 2004, an increase of $13.4 million, or 53%. The increase in treating plants in service from 74 plants at December 31, 2004 to 112 plants at December 31, 2005 contributed approximately $7.1 million in gross margin. Existing plant assets contributed $5.0 million in gross margin growth due primarily to plant expansion projects and increased volumes. The acquisition and installation of dew point control plants in 2005 contributed an additional $0.6 million to gross margin.

The profit on energy trading activities was $1.6 million for the year ended December 31, 2005 compared to $2.2 million for the year ended December 31, 2004. The decrease in profit on energy trading activities is primarily due to a volume decrease associated with contracts not renewed in 2005.

Operating Expenses. Operating expenses were $56.7 million for the year ended December 31, 2005 compared to $38.3 million for the year ended December 31, 2004, an increase of $18.4 million, or 48%. Increases of $5.3 million were associated with the acquisition of the South Louisiana Processing Assets from El Paso. LIG assets added $4.6 million of the variance due to the fact the assets were a part of our business for the entire year as opposed to nine months. Midstream operating expenses also increased by $2.6 million due to small acquisitions, expansions of systems and the addition of compressors or other rental services. The growth in treating plants in service due to acquisition of the Graco assets and the Cardinal assets as well as internal growth increased operating expenses by $5.2 million. Operations expenses included stock-based compensation expense of $0.4 million and $0.2 million in 2005 and 2004, respectively.

General and Administrative Expenses. General and administrative expenses were $32.7 million for the year ended December 31, 2005 compared to $20.9 million for the year ended December 31, 2004, an increase of

$11.8 million, or 57%. A significant part of the increased expenses was $6.0 million of additional staffing related costs. The staff additions required to manage and optimize our 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. Other expenses, including Sarbanes Oxley and other consulting fees, office rent, utilities, and travel expenses, accounted for $2.6 million of the increase. General and administrative expenses include stock-based compensation expense of $3.7 million and $0.8 million in 2005 and 2004, respectively. This increase in stock-based compensation primarily relates to restricted stock and unit grants and $0.4 million in accelerated options.

(Gain) Loss on Derivatives. We had a loss on derivatives of $10.0 million for the year ended December 31, 2005 compared to a gain on derivatives of $0.3 million for the year ended December 31, 2004. The loss in 2005 includes a $9.2 million loss on puts acquired in the third quarter of 2005 related to the acquisition of the South Louisiana Processing Assets and a loss of $0.8 million associated with derivatives for the third-party on-system financial transactions and storage financial transactions primarily due to higher commodity prices at year end. In August 2005, we acquired put options, or rights to sell a portion of the liquids from the plants at a fixed price over a two-year period beginning January 1, 2006 for a premium of $18.7 million as part of the overall risk management plan related to the acquisition of the South Louisiana Processing Assets which closed on November 1, 2005. In December 2005, we sold a portion of these puts for $4.3 million. We did not designate these options to obtain hedge accounting treatment as of December 31, 2005 and therefore, these put options did not qualify as hedges as of December 31, 2005 and were marked to market through our consolidated statement of operations. The puts represent options, but not the obligation, to sell the related underlying liquids volumes at a fixed price. As the price of the underlying liquids increased significantly in the period, the value of the puts declined, which is reflected in gain/loss on derivatives.

Gain on Sale of Property. During 2005, we sold an inactive gas processing facility acquired as part of the LIG acquisition, which accounted for a substantial part of the $8.1 million gain on sale of property.

Depreciation and Amortization. Depreciation and amortization expenses were $36.0 million for the year ended December 31, 2005 compared to $23.0 million for the year ended December 31, 2004, an increase of $13.0 million, or 56%. The acquisitions of the South Louisiana Processing Assets and the LIG assets contributed $5.5 million and $1.3 million, respectively. New treating plants placed in service and acquired resulted in an increase of $2.3 million. The remaining $3.9 million increase in depreciation and amortization is a result of expansion projects and other new assets, including the expansion of the Dallas office, computer software and equipment, and expansions on midstream assets.

Interest Expense. Interest expense was $15.8 million for the year ended December 31, 2005 compared to $9.2 million for the year ended December 31, 2004, an increase of $6.5 million, or 71%. The increase relates primarily to an increase in average debt outstanding due to borrowings for acquisitions and internal growth projects. Average interest rates also increased from 2004 to 2005 (weighted average rate of 6.3% in 2005 compared to 6.1% in 2004).

Other Income. Other income was $0.4 million for the year ended December 31, 2005 compared to $0.8 million for the year ended December 31, 2004. Other income in 2004 includes $0.3 million related to a reimbursement for a construction project in excess of our costs for such project.

Income Tax Expense. Income tax expense was $0.2 million for each of the years ended December 31, 2005 and 2004. 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.

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 generally accrue one to two months of sales and the related gas purchases and reverse these accruals when the sales and purchases are actually invoiced and recorded in the subsequent months. Actual results could differ from the accrual estimates.

We utilize extensive estimation procedures to determine the sales and cost of gas purchase accruals for each accounting cycle. Accruals are based on estimates of volumes flowing each month from a variety of sources. We use actual measurement data, if it is available, and will use such data as producer/shipper nominations, prior month average daily flows, estimated flow for new production and estimated end-user requirements (all adjusted for the estimated impact of weather patterns) when actual measurement data is not available. Throughout the month or two following production, actual measured sales and transportation volumes are received and invoiced and used in a process referred to as “actualization”. Through the actualization process, any estimation differences recorded through the accrual are reflected in the subsequent month’s accounting cycle when the accrual is reversed and actual amounts are recorded. Actual volumes purchased, processed or sold may differ from the estimates due to a variety of factors including, but not limited to: actual wellhead production or customer requirements being higher or lower than the amount nominated at the beginning of the month; liquids recoveries being higher or lower than estimated because gas processed through the plants was richer or leaner than estimated; the estimated impact of weather patterns being different from the actual impact on sales and purchases; and pipeline maintenance or allocation causing actual deliveries of gas to be different than estimated. We believe that our accrual process for the one to two months of sales and purchases provides a reasonable estimate of such sales and purchases.

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.

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 energy trading activities. In some cases, we earn an agency fee from the producer for arranging the marketing of the producer’s natural gas. In other cases, we purchase the natural gas from the producer and enter into a sales contract with another party to sell the natural gas.

We manage our price risk related to future physical purchase or sale commitments for energy trading activities by entering into either corresponding physical delivery contracts or financial instruments with an objective to balance future commitments and significantly reduce risk related to the movement in natural gas prices. However, we are subject to counter-party risk for both the physical and financial contracts. Our energy trading contracts qualify as derivatives, and we use mark-to-market accounting for both physical and financial contracts of the energy trading business. Accordingly, any gain or loss associated with changes in the fair value of derivatives and physical delivery contracts relating to energy trading activities are recognized in earnings as gain or loss on derivatives 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 net realized gains or losses on settled contracts, is reported net 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 $113.0 million for the year ended December 31, 2006 compared to $14.0 million for the year ended December 31, 2005. Income before non-cash income and expenses increased by $25.5 million from $62.8 million in 2005 to $88.3 million in 2006. Changes in working capital provided $24.7 million in cash flows from operating activities in 2006 as compared to $48.7 million in cash flows used by working capital changes in 2005. Our working capital deficit has increased in 2006, as discussed under "Working Capital Deficit" below.

Net cash used in investing activities was $885.8 million and $615.0 million for the year ended December 31, 2006 and 2005, respectively. Net cash used in investing activities during 2006 related to the $504.7 million Chief acquisition ($474.9 million paid to Chief, $0.4 million of direct acquisition costs and $29.4 million for assumed capital expenditure liabilities paid by us after acquisition), the $51.7 million Hanover acquisition, the $16.5 million acquisition of our additional interest in the Blue Water processing plant and the $6.3 million Cardinal Gas Solutions acquisition. Costs for the year ended December 31, 2006 associated with the pipeline and processing plant construction, connection of new wells to various systems, pipeline integrity projects, pipeline relocations and various other internal growth projects totaled $314.9 million. The most significant projects included in 2006 costs were the construction of the NTP of $48.2 million, construction of a processing plant in Parker County for the North Texas Assets of $76.1 million, the construction of the North Louisiana Pipeline Expansion of $38.5 million and the expansion of the North Texas Assets acquired from Chief of $31.0 million. Net cash used in investing activities during 2005 primarily related to the acquisition of the El Paso assets ($489.4 million), the Graco assets ($9.3 million) and the Cardinal assets ($6.7 million). The remaining cash used in investing activities for 2005 related to internal growth projects including expenditures of approximately $80.0 million for the NTP project, $21.2 million for buying, refurbishing and installing treating plants and $19.9 million for expansions, well connections and other capital projects on the pipeline, gathering and processing assets.

Net cash provided by financing activities was $772.2 million for the year ended December 31, 2006 compared to $596.6 million provided by financing activities for the year ended December 31, 2005. Net cash provided by financing activities for the year ended December 31, 2006 included $368.3 million from the issuance of senior subordinated series C units, including the general partner contribution, net bank borrowings of $166.0 million and net borrowings under our senior secured notes of $298.5 million. Financing activities in 2005 relate to proceeds from the sale of common units and subordinated units totaling $273.3 million and increased borrowings under our bank credit facility and senior secured notes totaling $374.0 million. Distributions to partners totaled $76.2 million in the year ended December 31, 2006 compared to distributions in the year ended December 31, 2005 of $43.3 million. Drafts payable decreased by $8.8 million requiring the use of cash in the year ended December 31, 2005 as compared to an increase in drafts payable of $18.1 million providing cash from financing activities for the year ended December 31, 2006. In order to reduce our interest costs, we do not borrow money to fund outstanding checks until 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 $79.9 million as of December 31, 2006, primarily due to drafts payable of $47.9 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 $1.0 billion credit facility to fund checks as they are presented. As of December 31, 2006, we had approximately $435.7 million of available borrowing capacity under this facility.

Off-Balance Sheet Arrangements. We had no off-balance sheet arrangements as of December 31, 2006 and 2005.

June 2006 Sale of Senior Subordinated Series C Units. On June 29, 2006, we issued an aggregate of 12,829,650 senior subordinated series C units representing limited partner interests in a private equity offering for net proceeds of $359.3 million. The senior subordinated series C units were issued at $28.06 per unit, which represented a discount of 25% to the market value of common units on such date. CEI purchased 6,414,830 of the senior subordinated series C units. In addition, Crosstex Energy GP, L.P. made a general partner contribution of $9.0 million in connection with this issuance to maintain its 2% general partner interest. The senior subordinated series C units will automatically convert to common units representing limited partner interests of the Partnership on the first date on or before February 16, 2008 that conversion is permitted by our partnership agreement at a ratio of one common unit for each senior subordinated series C unit.

November 2005 Sale of Senior Subordinated B Units. On November 1, 2005, we issued 2,850,165 senior subordinated series B units in a private placement for a purchase price of $36.84 per unit. We received net proceeds of approximately $107.1 million, including Crosstex Energy GP, L.P.’s general partner contribution of $2.1 million and expenses associated with the sale. The senior subordinated series B units automatically converted into common units on November 14, 2005 at a ratio of one common unit for each senior subordinated series B unit and were not entitled to distributions paid on November 14, 2005.

November 2005 Public Offering. In November and December 2005, we issued 3,731,050 common units to the public at a purchase price of $33.25 per unit. The offering resulted in net proceeds to the Partnership of $120.9 million, including Crosstex Energy GP, L.P.’s general partner contribution of $2.5 million and net of expenses associated with the offering.

June 2005 Sale of Senior Subordinated Units. In June 2005, we issued 1,495,410 senior subordinated units in a private equity offering for net proceeds of $51.1 million, including Crosstex Energy GP, L.P.’s general partner contribution of $1.1 million. These units automatically converted to common units on a one-for-one basis on February 24, 2006. The senior subordinated units received no distributions until their conversion to common units in February 2006.

Bank Credit Facility. On June 29, 2006, we amended our bank credit facility increasing availability under the facility to $1.0 billion. The bank credit agreement includes procedures for additional financial institutions selected by us to become lenders under the agreement, or for any existing lender to increase its commitment in an amount approved by us and the lender, subject to a maximum of $300 million for all such increases in commitments of new or existing lenders. The maturity date was also extended to June 2011.

Senior Secured Notes. In March 2006, we completed another private placement of $60.0 million of senior secured notes pursuant to our master shelf agreement with an institutional lender with an interest rate of 6.32% and a maturity of ten years. In July 2006, we issued $245.0 million of senior secured notes with an interest rate of 6.96% and a maturity of ten years.

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 and large capital expansions, we anticipate that we will continue to invest significant amounts of capital to grow and to build and acquire assets. We actively consider a variety of assets for potential development or acquisition.

We believe that cash generated from operations will be sufficient to meet our present quarterly distribution level of $0.56 per quarter and to fund a portion of our anticipated capital expenditures through December 31, 2007. Total capital expenditures are budgeted to be approximately $260.0 million in 2007. We expect to fund the remaining capital expenditures from the proceeds of borrowings under the revolving credit facility discussed below, and with 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, 2006, is as follows:

	Payments Due by Period						
	Total	2007	2008	2009 (In millions)	2010	2011	Thereafter
Long-Term Debt	$ 987.1	$ 10.0	$ 9.4	$ 9.4	$ 20.3	$ 520.0	$ 418.0
Capital Lease Obligations	—	—	—	—	—	—	—
Operating Leases	103.2	18.7	17.8	17.1	16.0	16.0	17.6
Unconditional Purchase Obligations	4.6	4.6	—	—	—	—	—
Other Long-Term Obligations	—	—	—	—	—	—	—
Total Contractual Obligations	$ 1,094.9	$ 33.3	$ 27.2	$ 26.5	$ 36.3	$ 536.0	$ 435.6

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

The unconditional purchase obligations for 2007 relate to purchase commitments for equipment. We have also committed to contract for 150,000 MMBtus/day of firm transportation capacity on a pipeline that is expected to be in service in the fourth quarter of 2008. This commitment is not reflected in the summary above since the pipeline is not yet constructed.

Description of Indebtedness

As of December 31, 2006 and 2005, long-term debt consisted of the following:

	December 31, 2006	December 31, 2005
	(In thousands)	
Bank credit facility, interest based on Prime or LIBOR plus an applicable margin, interest rates at December 31, 2006 and 2005 were 7.20% and 6.69%, respectively	$ 488,000	$ 322,000
Senior secured notes, weighted average interest rate of 6.76% and 6.64%, respectively	498,530	200,000
Note payable to Florida Gas Transmission Company	600	650
	987,130	522,650
Less current portion	(10,012)	(6,521)
Debt classified as long-term	$ 977,118	$ 516,129

On June 29, 2006, we amended our bank credit facility, increasing availability under the facility to $1.0 billion and extending the maturity date from November 2010 to June 2011. The bank credit agreement includes procedures for additional financial institutions selected by us to become lenders under the agreement, or for any existing lender to increase its commitment in an amount approved by us and the lender, subject to a maximum of $300 million for all such increases in commitments of new or existing lenders.

The credit facility was used for the El Paso, Chief and Hanover acquisitions 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, 2006, $564.3 million was outstanding under the credit facility, including $76.3 million of letters of credit, leaving approximately $435.7 available for future borrowings. The credit facility will mature in June 2011, at which time it will terminate and all outstanding amounts shall be due and payable. Amounts borrowed and repaid under the credit facility may be re-borrowed.

The obligations under the bank credit facility are secured by first priority liens on all of our material pipeline, gas gathering, treating, 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.

Under the amended credit agreement, borrowings bear interest at our option at the administrative agent's reference rate plus 0% to 0.25% or LIBOR plus 1.00% to 1.75%. The applicable margin varies quarterly based on our leverage ratio. The fees charged for letters of credit range from 1.00% to 1.75% per annum, plus a fronting fee of 0.125% per annum. We will incur quarterly commitment fees ranging from 0.20% to 0.375% on the unused amount of the credit facilities. The amendment to the credit facility also adjusted financial covenants requiring us to maintain:

- an initial ratio of total funded debt to consolidated earnings before interest, taxes, depreciation and amortization (each as defined in the credit agreement), measured quarterly on a rolling four-quarter basis, of 5.25 to 1.00, pro forma for any asset acquisitions. The maximum leverage ratio is reduced to 4.75 to 1.00 beginning July 1, 2007 and further reduces to 4.25 to 1.00 on January 1, 2008. The maximum leverage ratio increases to 5.25 to 1.00 during an acquisition adjustment period, as defined in the credit agreement; and
- a minimum interest coverage ratio (as defined in the credit agreement), measured quarterly on a rolling four quarter basis, equal to 3.0 to 1.0.

Additionally, the bank credit facility was amended to allow for borrowings under our senior secured note shelf agreement to increase from $260 million to $510 million.

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 our business;
- enter into certain commodity contracts;
- make certain amendments to our or the operating partnership's partnership agreement; and
- engage in transactions with affiliates.

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.

In November 2006, we entered into an interest rate swap covering a principal amount of $50.0 million under the credit facility for a period of three years. We are subject to interest rate risk on our credit facility. The interest rate swap reduces this risk by fixing the LIBOR rate, prior to credit margin, at 4.95%, on $50.0 million of related debt outstanding over the term of the swap agreement which expires on November 30, 2009. We have elected not to designate this swap as a cash flow hedge for FAS 133 accounting treatment. Accordingly, unrealized gains or losses relating to the swap flow through the Consolidated Statement of Operations as adjustments to interest expense over the period hedged. The fair value of the interest rate swap at December 31, 2006 was a $0.1 million asset.

Senior Secured Notes. We entered into a master shelf agreement with an institutional lender in 2003 that was amended in subsequent years to increase availability under the agreement, to $510.0 million, pursuant to which we issued the following senior secured notes:

Month Issued	Amount (In thousands)	Interest Rate	Maturity
June 2003	$ 30,000	6.95%	7 years
July 2003	10,000	6.88%	7 years
June 2004	75,000	6.96%	10 years
November 2005	85,000	6.23%	10 years
March 2006	60,000	6.32%	10 years
July 2006	245,000	6.96%	10 years
Total issued	505,000		
Principal repaid	(6,470)		
Balance as of December 31, 2006	$ 498,530		

These notes represent 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 $40.0 million of senior secured notes issued in 2003 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 senior secured notes issued in 2004, 2005 and 2006 provide for a call premium of 103.5% of par beginning three years after issuance at rates declining from 103.5% to 100.0%. The notes are not callable prior to three years after issuance. During 2007 the notes may also incur an additional fee each quarter ranging from 0.08% to 0.15% per annum on the outstanding borrowings if our leverage ratio exceeds certain levels as defined in the agreement, during such quarterly periods.

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, 2006 and 2005 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, the lenders under the bank credit facility and the 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 appoints Bank of America, N.A. to act as collateral agent and authorized Bank of America to execute various security documents on behalf of the lenders under the bank credit facility and the 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 our 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 and NGLs 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, 2004, 2005 or 2006. 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.”

Recent Accounting Pronouncements

In June 2006, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 48 (FIN 48), *“Accounting for Uncertainty in Income Taxes”.* FIN 48 is an interpretation of FASB Statement No. 109, *“Accounting for Income Taxes”* and must be adopted no later than January 1, 2007. FIN 48 prescribes a comprehensive model for recognizing, measuring, presenting and disclosing in the financial statements uncertain tax positions taken or expected to be taken. We are a pass-thru entity and do not expect a major impact on financial statements as a result of FIN 48.

On September 13, 2006, the Securities and Exchange Commission, or SEC, issued Staff Accounting Bulleting No. 108 (“SAB 108”), which establishes an approach that requires quantification of financial statement errors based on the effects of the error on each of the company’s financial statements and the related disclosures. SAB 108 requires the use of a balance sheet and an income statement approach to evaluate whether either of these approaches results in quantifying a misstatement that, when all relevant quantitative and qualitative factors are considered, is material.

Disclosure Regarding Forward-Looking Statements

This Annual Report on Form 10-K contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, that are based on information currently available to management as well as management’s assumptions and beliefs. All statements, other than statements of historical fact, included in this Form 10-K constitute forward-looking statements, including but not limited to statements identified by the words “may,” “will,” “should,” “plan,” “predict,” “anticipate,” “believe,” “intend,” “estimate” and “expect” and similar expressions. Such statements reflect our current views with respect to future events, based on what we believe are reasonable assumptions; however, such statements are subject to certain risks and uncertainties. In addition to the specific uncertainties discussed elsewhere in this Form 10-K, the risk factors set forth in “Item 1A. Risk Factors” may affect our performance and results of operations. 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.

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 NGLs. In addition, we are also exposed to the risk of changes in interest rates on our floating rate debt.

Interest Rate Risk

We are exposed to interest rate risk on short-term and long-term debt carrying variable interest rates. At December 31, 2006 and 2005, our variable rate debt had a carrying value of $488.6 million and $322.7 million, respectively, which approximated its fair value, and our fixed rate debt had a carrying value of $498.5 million and $200.0 million, respectively, and an approximately fair value of $503.9 million and $203.9 million, respectively. We attempt to balance variable rate debt, fixed rate debt and debt maturities to manage interest cost, interest rate volatility and financing risk. This is accomplished through a mix of bank debt with short-term variable rates and fixed rate senior and subordinated debt. In addition, the Partnership entered into an interest rate swap in November 2006 covering $50.0 million of the variable rate debt for a period of three years.

The following table shows the carrying amount and fair value of long-term debt and the hypothetical change in fair value that would result from a 100-basis point change in interest rates. Unless otherwise noted, the hypothetical change in fair value could be a gain or a loss depending on whether interest rates increase or decrease.

	Carrying Amount	Fair Value(a)	Hypothetical Change in Fair Value
		(In millions)	
December 31, 2006 Long-term debt	$ (987.1)	$ (996.9)	$ 9.8
December 31, 2005 Long-term debt	$ (522.7)	$ (529.8)	$ 7.1

(a) Fair value is based upon current market quotes and is the estimated amount required to purchase our long-term debt on the open market. This estimated value does not include any redemption premium.

Commodity Price Risk

Approximately 5.9% of the natural gas we market is purchased at a percentage of the relevant natural gas index price, as opposed to a fixed discount to that price. As a result of purchasing the natural gas at a percentage of the index price, our resale margins are higher during periods of high natural gas prices and lower during periods of lower natural gas prices. As of December 31, 2006, we have hedged approximately 78% of our exposure to natural gas price fluctuations through December 2007 and approximately 70% of our exposure to natural gas price fluctuations for the first quarter of 2008. We also have hedges in place covering at least 100% of the minimum liquid volumes we expect to receive through the end of 2007 and approximately 25% for the first quarter of 2008 at our south Louisiana assets; and 81% of the liquids at our other assets in 2007 and 40% for the first quarter of 2008.

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 NGLs 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.

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 credit 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 arising from changes to the fair market value of the derivative and physical delivery contract related to our producer services natural gas marketing activities are recognized in earnings as profit or loss from energy trading contracts immediately.

For each reporting period, we record the fair value of open energy trading contracts based on the difference between the quoted market price and the contract price. Accordingly, the change in fair value from the previous period is reported as a gain or loss on derivatives in the statement of operations. Realized gains and losses from settled contracts accounted for as cash flow hedges are recorded in Midstream Revenue. As of December 31, 2006, outstanding natural gas swap agreements, NGL swap agreements, swing swap agreements, storage swap agreements and other derivative instruments were a net fair value asset of $10.4 million, excluding the fair value asset of $1.7 million associated with the natural gas liquids puts. The aggregate effect of a hypothetical 10% increase in gas and NGLs prices would result in a decrease of approximately $4.8 million in the net fair value asset of these contracts as of December 31, 2006. The value of the natural gas liquids puts would also decrease as a result of an increase in NGLs prices but we are unable to determine the impact of a 10% price change. Our maximum loss on these puts is the remaining $1.7 million recorded fair value for the puts.

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-41 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***

(a) ***Evaluation of Disclosure 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 pursuant to Exchange Act Rules 13a-15 and 15d-15. 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, 2006 in alerting them in a timely manner to material information required to be disclosed in our reports filed with the Securities and Exchange Commission.

(b) ***Changes in Internal Control Over Financial Reporting***

There has been no change in our internal controls over financial reporting that occurred in the three months ended December 31, 2006 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, Executive Officers and Corporate Governance***

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 general partner, Crosstex Energy GP, L.P. 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	45	President, Chief Executive Officer and Director
Robert S. Purgason	50	Executive Vice President — Chief Operating Officer
James R. Wales	53	Executive Vice President — Commercial
A. Chris Aulds	45	Executive Vice President — Public and Governmental Affairs
Jack M. Lafield	56	Executive Vice President — Corporate Development
William W. Davis	53	Executive Vice President and Chief Financial Officer
Joe A. Davis	46	Executive Vice President, General Counsel and Secretary
Danny L. Thompson	57	Senior Vice President — Engineering and Operations
Rhys J. Best**	60	Director and Member of the Conflicts Committee* and Compensation Committee
Frank M. Burke **	67	Director and Member of the Audit Committee*
James C. Crain **	58	Director and Member of the Audit Committee
Bryan H. Lawrence	64	Chairman of the Board
Sheldon B. Lubar **	77	Director and Member of the Compensation Committee*
Cecil E. Martin **	65	Director and Member of the Audit Committee
Robert F. Murchison **	53	Director and Member of the Compensation Committee
Kyle D. Vann **	59	Director and Member of the Conflicts 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.

Robert S. Purgason, Executive Vice President — Chief Operating Officer, joined Crosstex in October 2004 as Senior Vice President — Treating Division to lead the Treating Division and was promoted to Executive Vice President — Chief Operating Officer in November 2006. 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.

James R. Wales, Executive Vice President — Commercial, 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 — Public and Governmental Affairs, 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, Inc., 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 or Joe A. Davis.

Joe A. Davis, Executive Vice President, General Counsel and Secretary, joined Crosstex in October 2005. He began his legal career with the Dallas firm of Worsham Forsythe, which merged with the international law firm of Hunton & Williams in 2002. Most recently, he served as a partner in the firm's Energy Practice Group, and served on the firm's Executive Committee. Mr. Davis specialized in facility development, sales, acquisitions and financing for the energy industry, representing entrepreneurial start up/development companies, growth companies, large public corporations and large electric and gas utilities. He received his J.D. from Baylor Law School in Waco and his B.S. degree from the University of Texas in Dallas. Mr. Davis is not related to Barry E. Davis or William W. Davis.

Danny L. Thompson, Senior Vice President — Engineering and Operations, has held various leadership positions within the midstream energy industry. From March 2005 until August 2005 when he became an employee of Crosstex, he worked with Crosstex as a consultant. Prior to joining Crosstex, he worked for Cantera Natural Gas L.L.C. as vice president, operations and engineering and CMS Field Services as director of engineering and operations. Mr. Thompson holds a bachelor's degree in chemical engineering from Texas A&I University in Kingsville, and he is a registered professional engineer in Texas.

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. and Corrigan Investments, Inc. 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.

James C. Crain joined Crosstex Energy GP, LLC as a director in December 2005. Since 1989, Mr. Crain has served as president of Marsh Operating Company, where he has worked since 1989, an investment management company focusing on energy investing, and since 1997 as general partner of Valmora Partners, L.P., a private investment partnership. Prior to Marsh, he served as a partner at Jenkens & Gilchrist where he headed the law firm's energy section. He graduated from the University of Texas at Austin with a B.B.A. degree, a master of professional accounting and a doctor of jurisprudence. Mr. Crain also serves on the boards of GeoMet, Inc., a publicly traded company, and of the Texas State Historical Association.

Bryan H. Lawrence, Chairman of the Board, joined Crosstex Energy GP, LLC 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 Hallador Petroleum Company, and StarGas L.P. (each a United States publicly traded company) and Winstar Resources Ltd. (a Canadian public company) and certain non-public companies in the energy industry in which Yorktown partnerships hold equity interests. 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 Crosstex Energy GP, LLC 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 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.

Cecil E. Martin, Jr., joined Crosstex Energy GP, LLC as a director in January 2006. He has been an independent residential and commercial real estate investor since 1991. From 1973 to 1991 he served as chairman of the public accounting firm Martin, Dolan and Holton in Richmond, Virginia. He began his career as an auditor at Ernst and Ernst. He holds a B.B.A. degree from Old Dominion University and is a Certified Public Accountant. Mr. Martin also serves on the boards and as chairman of the audit committees for both Comstock Resources, Inc., a growing independent energy company engaged in oil and gas acquisitions, exploration and development, and Bois d'Arc Energy, Inc., headquartered in Houston. Mr. Martin also has served as a director of Crosstex Energy, Inc. since January 2006.

Robert F. Murchison joined Crosstex Energy GP, LLC 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.

Kyle D. Vann joined Crosstex Energy GP, LLC as a director in April 2006. Mr. Vann began his career with Exxon Corporation in 1969. After ten years at Exxon, he joined Koch Industries and served in various leadership capacities, including senior vice president from 1995 to 2000. In 2001, he then took on the role of CEO with Entergy-Koch, LP, a profitable energy trading and transportation company, which was sold in 2004. Currently, Mr. Vann, who is retired, continues to consult with Entergy and Texon, L.P. He also serves on the boards of Texon, L.P. and Legacy Reserves, LLC. Mr. Vann graduated from the University of Kansas with a Bachelor of Science degree in chemical engineering. He is a member of the Board of Advisors for the University of Kansas School of Engineering. Mr. Vann also serves on the board of various charitable organizations.

Independent Directors

Messrs. Best, Burke, Crain, Lubar, Martin, Murchison and Vann 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 also each qualify as "independent" under special standards established by the 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. Messrs. Burke and Martin are both independent directors who have been determined to be audit committee financial experts. Unitholders should understand that this designation is a disclosure requirement of the SEC related to experience and understanding with respect to certain accounting and auditing matters. The designation does not impose any duties, obligations or liability that are greater than are generally imposed on a member of the Audit Committee and board of directors, and the designation of a director 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 Denise LeFevre at 214-721-9245 to request a copy of a charter or send your request to Crosstex Energy, L.P., Attn: Denise LeFevre, 2501 Cedar Springs, Dallas, Texas 75201.

The Audit Committee, comprised of Messrs. Burke (chair), Martin and Crain, 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.

The Conflicts Committee, comprised of Messrs. Best (chair) and Vann, reviews specific matters that the board believes may involve conflicts of interest between our general partner and Crosstex Energy, L.P. The Conflicts Committee determines if the resolution of a conflict of interest is fair and reasonable to us. The members of the Conflicts Committee are not officers or employees of our general partner or directors, officers or employees of its affiliates. Any matters approved by the Conflicts Committee will be conclusively deemed to be fair and reasonable to us, approved by all of our partners, and not a breach by our general partner of any duties owed to us or our unitholders.

The Compensation Committee, comprised of Messrs. Lubar (chair), Murchison, and Best, 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 Denise LeFevre at 214-721-9245 to request a copy of the Code or send your request to Crosstex Energy, L.P., Attn: Denise LeFevre, 2501 Cedar Springs, 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 set forth below, we believe that during 2006 all reporting persons complied with the Section 16(a) filing requirements applicable to them. Due to administration errors, Form 4s were filed late on behalf of Jack M. Lafield on March 23, 2006 and May 4, 2006; Barry E. Davis on May 4, 2006; A. Chris Aulds on May 4, 2006; William W. Davis on May 4, 2006; James R. Wales on May 5, 2006; Susan McAden on September 1, 2006; and Frank M. Burke on January 24, 2007. On December 12, 2006, a Form 3 was filed on behalf of Robert Purgason with respect to his appointment to the office of Executive Vice President — Chief Operating Officer effective November 15, 2006.

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.

Item 11. ***Executive Compensation***

Compensation Discussion and Analysis

We do not directly employ any of the persons responsible for managing our business. Crosstex Energy GP, LLC, the general partner of our general partner, manages our operations and activities, and its board of directors and officers make decisions on our behalf. The compensation of the directors, officers and employees of Crosstex Energy GP, LLC is determined by the Compensation Committee of the board of directors of Crosstex Energy GP, LLC. Our named executive officers also serve as executive officers of Crosstex Energy, Inc. and the compensation of the named executive officers discussed below reflects total compensation for services to all Crosstex entities. We reimburse 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. Our partnership agreement provides that our general partner will determine the expenses allocable to us in any reasonable manner determined by our general partner in its sole discretion. Crosstex Energy, Inc. currently pays a monthly fee to us to cover its portion of administrative and compensation costs, including compensation costs relating to the named executive officers.

Crosstex Energy GP, LLC's Compensation Committee assists the board of directors in discharging its responsibilities relating to compensation of executive officers and directors and has overall responsibility for approval, evaluation and oversight of all compensation plans, policies and programs of Crosstex Energy GP, LLC. Each member of the Crosstex Energy GP, LLC's Compensation Committee is an independent director in accordance with NASDAQ standards. The responsibilities of Crosstex Energy GP, LLC's Compensation Committee, as stated in its charter, include the following:

- reviewing and making recommendations to the board of directors, on at least an annual basis, with respect to general compensation policies of Crosstex Energy GP, LLC relating to all officers and other key executives and directors;
- reviewing and making recommendations to the board of directors, on at least an annual basis, for the annual base salary, award of options, awards under incentive compensation and equity-based plans, employment agreements, severance agreements, and change in control agreements and any special or supplemental benefits for senior executives;
- reviewing and making recommendations to the board of directors with respect to goals and objectives relevant to the compensation of senior executives, evaluating the senior executives' performance in light of these goals and objectives and recommending compensation levels based on this evaluation; and
- reviewing and reassessing the adequacy of the Compensation Committee's charter, on at least an annual basis, and recommending any proposed changes to the board of directors.

Compensation Philosophy and Policies. The primary objectives of Crosstex Energy GP, LLC's compensation program, including compensation of the named executive officers, are to attract and retain highly qualified officers, employees and directors and to reward individual contributions to our success. Crosstex Energy GP, LLC considers the following policies in determining the compensation of the named executive officers:

- compensation should be related to performance of the individual executive and the performance of the executive's division/executive team (measured against both financial and non-financial goals);
- incentive compensation should represent a significant portion of the executive's total compensation;
- compensation levels should be competitive to ensure that we will be able to attract, motivate and retain highly qualified executive officers;
- incentive compensation should balance long and short-term performance; and
- compensation should be related to improving unitholder value.

Compensation Methodology. The elements of Crosstex Energy GP, LLC's compensation program for named executive officers are intended to provide a total incentive package designed to drive performance and reward contributions in support of business strategies at the entity and individual levels. All compensation determinations are discretionary and, as noted above, subject to the decision-making authority of Crosstex Energy GP, LLC.

Compensation Consultant. In 2006, Crosstex Energy GP, LLC's Compensation Committee retained Mercer Human Resource Consulting ("Mercer") as its independent compensation consultant to conduct a compensation study and advise the Compensation Committee on certain matters relating to compensation programs applicable to the named executive officers and other employees of Crosstex Energy GP, LLC. Mercer provided a presentation to the Compensation Committee regarding the compensation programs of the Crosstex entities in February 2007.

With respect to compensation objectives and decisions regarding the named executive officers Crosstex Energy GP, LLC's Compensation Committee has reviewed market data with respect to peer companies provided by Mercer and its previous consultants for determining relevant compensation levels and compensation program elements, including base salary and bonus structure and methodology, short and long-term compensation elements and assessment of competitiveness. Mercer has provided guidance on current industry best practices to the Compensation Committee. In addition, Crosstex Energy GP, LLC's Compensation Committee has reviewed various relevant compensation surveys with respect to determining compensation for the named executive officers. In determining the long-term incentive component of compensation of the senior executives of Crosstex Energy GP, LLC (including the chief executive officer), the Compensation Committee considers the performance and relative equity holder return, the value of similar incentive awards to senior executives at comparable companies, awards made to the company's senior executives in past years and such other factors as the Compensation Committee deems relevant.

Elements of Compensation. The primary elements of Crosstex Energy GP, LLC's compensation program are a combination of annual cash and long-term equity-based compensation. For fiscal year 2006, the principal elements of compensation for the named executive officers were the following:

- base salary;
- discretionary cash bonus awards;
- long-term incentive plan awards; and
- retirement and health benefits.

Base Salary. Crosstex Energy GP, LLC's Compensation Committee establishes base salaries for the named executive officers based on the historical salaries for services rendered to Crosstex Energy GP, LLC and its affiliates, market data and responsibilities of the named executive officers. Salaries are generally determined by considering the employee's performance and prevailing levels of compensation in areas in which a particular employee works. As discussed above, except with respect to the monthly payment received from Crosstex Energy, Inc., all of the base salaries of the named executive officers were allocated to us by Crosstex Energy GP, LLC as general and administration expenses. The base salaries paid to our named executive officers during fiscal year 2006 are shown in the Summary Compensation Table on page 60.

Each of the named executive officers, including Barry E. Davis, James R. Wales, Jack M. Lafield, William W. Davis and Robert S. Purgason, have entered into employment agreements with Crosstex Energy GP, LLC. 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 $390,000, $275,000, $275,000, $275,000 and $275,000 for Barry E. Davis, James R. Wales, Jack M. Lafield, William W. Davis and Robert S. Purgason, respectively, as of January 1, 2007.

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 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.

Robert S. Purgason's employment agreement also provides that, for a three-year period commencing in October 2004, we will reimburse him for a living allowance of $4,475.73 per month relating to Mr. Purgason's relocation from Tulsa, Oklahoma and related living expenses in Dallas, Texas. This living allowance continues through October 2007.

Discretionary Cash Bonus Awards. Crosstex Energy GP, LLC's Compensation Committee awarded discretionary cash bonus awards to each of the named executive officers in 2006. Crosstex uses cash bonus awards to reward achieving financial and operational goals and for achieving individual performance objectives. Bonuses are generally based on return on invested capital ("ROI"), bottom-line profitability, customer satisfaction, overall company growth, corporate governance, adherence to policies and procedures and other factors that vary depending on an employee's responsibilities. As in past years, a majority of the bonuses payable to the named executive officers were based upon a formula that is tied to ROI achieved by us during the year. If a predetermined ROI is accomplished, then the bonus is paid and is increased or decreased based on the ROI percentage that is achieved, with minimum payouts of 10%, target payouts ranging from 40% to 60%, and maximum payouts ranging from 75% to 120% of an executive officer's base salary.

Long-Term Incentive Plans. We compensate our employees and directors with grants from long-term incentive plans adopted by each of Crosstex Energy GP, LLC and Crosstex Energy, Inc. A discussion of each plan follows:

Crosstex Energy GP, LLC Long-Term Incentive Plan. Crosstex Energy GP, LLC has 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 is administered by Crosstex Energy GP, LLC's Compensation Committee and permits the grant of awards covering an aggregate of 2,600,000 common units, which may be awarded in the form of restricted units or unit options. Of the 2,600,000 common units that may be awarded under the long-term incentive plan, 844,591 common units remain eligible for future grants by Crosstex Energy GP, LLC as of January 1, 2007. The long-term compensation structure is intended to align the employee's performance with long-term performance for our unitholders.

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. 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 Compensation 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, as discussed below under "— Potential Payments Upon a Change of Control or Termination." 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. Under current policy all unit option grants will be 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, as discussed below under "— Potential Payments Upon a Change of Control or Termination." 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.

On an aggregate basis, in the past the Crosstex entities generally have granted equity compensation in a amount of up to 300% of the chief executive officer's base salary and up to 200% of each other named executive officer's base salary. The total value of the equity compensation granted to our named executive officers generally has been allocated 50% in restricted units of Crosstex Energy, L.P. and 50% in restricted stock of Crosstex Energy, Inc. For fiscal year 2006, Crosstex Energy GP, LLC granted 16,667, 7,971, 10,145, 10,145 and 18,886 restricted units to Barry E. Davis, James R. Wales, Jack M. Lafield, William W. Davis and Robert S. Purgason, respectively. All restricted units granted to our executive officers are expensed to us.

Crosstex Energy, Inc. Long-Term Incentive Plan. The objectives of Crosstex Energy, Inc.'s long-term incentive plan are to attract able persons to enter the employ of the company, to encourage employees to remain in the employ of the company, to provide motivation to employees to put forth maximum efforts toward the continued growth, profitability and success of the company by providing incentives to such persons through the ownership and/or performance of Crosstex Energy, Inc.'s common stock and to attract able persons to become directors of the company and to provide such individuals with incentive and reward opportunities. Awards to participants under the long-term incentive plan may be made in the form of stock options or restricted stock awards.

The Crosstex Energy, Inc. long-term incentive plan provides for the award of stock options and restricted stock (collectively, "Awards") for up to 4,590,000 shares of Crosstex Energy, Inc.'s common stock. As of January 1, 2007, approximately 1,123,215 shares remained available under the long-term incentive plan for future issuance to participants. A participant may not receive in any calendar year options relating to more than 100,000 shares of common stock. The maximum number of shares set forth above are subject to appropriate adjustment in the event of a recapitalization of the capital structure of Crosstex Energy, Inc. or reorganization of Crosstex Energy, Inc. Shares of common stock underlying Awards that are forfeited, terminated or expire unexercised become immediately available for additional Awards under the long-term incentive plan.

The Compensation Committee of Crosstex Energy, Inc.'s board of directors administers the long-term incentive plan. The administrator has the power to determine the terms of the options or other awards granted, including the exercise price of the options or other awards, the number of shares subject to each option or other award, the exercisability thereof and the form of consideration payable upon exercise. In addition, the administrator has the authority to grant waivers of long-term incentive plan terms, conditions, restrictions and limitations, and to amend, suspend or terminate the plan, provided that no such action may affect any share of common stock previously issued and sold or any option previously granted under the plan without the consent of the holder. Awards may be granted to employees, consultants and outside directors of Crosstex Energy, Inc.

The Compensation Committee of Crosstex Energy, Inc. will determine the type or types of Awards made under the plan and will designate the individuals who are to be the recipients of Awards. Each Award may be embodied in an agreement containing such terms, conditions and limitations as determined by the Compensation Committee of Crosstex Energy, Inc. Awards may be granted singly or in combination. Awards to participants may also be made in combination with, in replacement of, or as alternatives to, grants or rights under the plan or any other employee benefit plan of the company. All or part of an Award may be subject to conditions established by the Compensation Committee of Crosstex Energy, Inc., including continuous service with the company.

The types of Awards to participants that may be made under the Crosstex Energy, Inc. long-term incentive plan are as follows:

- *Stock Options.* Stock options are rights to purchase a specified number of shares of common stock at a specified price. An option granted pursuant to the plan may consist of either an incentive stock option that complies with the requirements of section 422 of the Code, or a nonqualified stock option that does not comply with such requirements. Only employees may receive incentive stock options and such options must have an exercise price per share that is not less than 100% of the fair market value of the common stock underlying the option on the date of grant. Nonqualified stock options also must have an exercise price per share that is not less than the fair market value of the common stock underlying the option on the date of grant. The exercise price of an option must be paid in full at the time an option is exercised.

- *Restricted Stock Awards.* Stock awards consist of restricted shares of common stock of Crosstex Energy, Inc. The Compensation Committee of Crosstex Energy, Inc. will determine the terms, conditions and limitations applicable to any restricted stock awards. Rights to dividends or dividend equivalents may be extended to and made part of any stock award at the discretion of the Crosstex Energy, Inc. Compensation Committee. Restricted stock awards will have a vesting period established in the sole discretion of the Compensation Committee, provided that the Compensation Committee may provide for earlier vesting by reason of death, disability, retirement or otherwise.

Crosstex Energy, Inc.'s board of directors may amend, modify, suspend or terminate the long-term incentive plan for the purpose of addressing any changes in legal requirements or for any other purpose permitted by law, except that no amendment that would impair the rights of any participant to any Award may be made without the consent of such participant, and no amendment requiring stockholder approval under any applicable legal requirements will be effective until such approval has been obtained. No incentive stock options may be granted after the tenth anniversary of the effective date of the plan.

In the event of any corporate transaction such as a merger, consolidation, reorganization, recapitalization, separation, stock dividend, stock split, reverse stock split, split up, spin-off or other distribution of stock or property of Crosstex Energy, Inc., the Crosstex Energy, Inc. board of directors shall substitute or adjust, as applicable: (i) the number of shares of common stock reserved under this plan and the number of shares of common stock available for issuance pursuant to specific types of Awards as described in the plan, (ii) the number of shares of common stock covered by outstanding Awards, (iii) the grant price or other price in respect of such Awards and (iv) the appropriate fair market value and other price determinations for such Awards, in order to reflect such transactions, provided that such adjustments shall only be such that are necessary to maintain the proportionate interest of the holders of Awards and preserve, without increasing, the value of such Awards.

As discussed above, on an aggregate basis, in the past the Crosstex entities generally have granted equity compensation in a amount of up to 300% of the chief executive officer's base salary and up to 200% of each other named executive officer's base salary. The total value of the equity compensation granted to our executive officers is generally has been awarded 50% in restricted units of Crosstex Energy, L.P. and 50% in restricted stock of Crosstex Energy, Inc. In addition, our executive officers may receive additional grants of equity compensation in certain circumstances, such as promotions. For fiscal year 2006, Crosstex Energy, Inc. granted 23,154, 11,073, 14,094, 14,094 and 23,631 shares of restricted stock to Barry E. Davis, James R. Wales, Jack M. Lafield, William W. Davis and Robert S. Purgason, respectively.

Retirement and Health Benefits. Crosstex Energy GP, LLC offers a variety of health and welfare and retirement programs to all eligible employees. The named executive officers are generally eligible for the same programs on the same basis as other employees of Crosstex Energy GP, LLC. Crosstex Energy GP, LLC maintains a tax-qualified retirement plan that provides eligible employees with an opportunity to save for retirement on a tax advantages basis. Crosstex Energy GP, LLC matches 60% of every dollar contributed for contributions of up to 5% of salary (not to exceed the maximum amount permitted by law) made by eligible participants. The retirement benefits provided to the named executive officers were allocated to us as general and administration expenses. Our executive officers are also eligible to participate in any additional retirement and health benefits available to our other employees.

Perquisites and Other Compensation. Crosstex Energy GP, LLC generally does not pay for perquisites for any of the named executive officers, other than payment of dues, sales tax and related expenses for membership in a private lunch club (totaling less than $2,500 per year per person), and expects this policy to continue. As discussed above, Robert S. Purgason will also receive a living allowance of $4,475.73 per month pursuant to his employment agreement until October 2007.

The equity-based awards to both the named executive officers and the directors of our general partner are intended to align their long-term interests with those of our unitholders.

Compensation Mix. Crosstex Energy GP, LLC's Compensation Committee determines the mix of compensation, both among short and long-term compensation and cash and non-cash compensation, to establish structures that it believes are appropriate for each of the named executive officers. We believe that the mix of base salary, cash bonus awards, awards under the long-term incentive plan, retirement and health benefits and perquisites and other compensation fit our overall compensation objectives. We believe this mix of compensation provides competitive compensation opportunities to align and drive employee performance in support of our business strategies and to attract, motivate and retain high quality talent with the skills and competencies that we require.

Potential Payments Upon a Change of Control or Termination.

Employment Agreements. Under the employment agreements with our executive officers, we may be required to pay certain amounts upon a change of control of us or our affiliates or upon the termination of the executive officer in certain circumstances. Except in the event of our becoming bankrupt or ceasing operations, termination for cause or termination by the employee other than for good reason, or 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 employment agreements entered into between Crosstex Energy GP, LLC and each of the named executive officers provide for continued salary payments, bonus and benefits following termination of employment for the remainder of the employment term under the agreement. For purposes of the employment agreements:

- "Cause" means that:
  - the employee has failed to perform the duties assigned to him and such failure has continued for 30 days following delivery by Crosstex Energy GP, LLC of written notice to the employee of such failure;
  - the employee has been convicted of a felony or misdemeanor involving moral turpitude;
  - the employee has engaged in acts or omissions against Crosstex Energy GP, LLC constituting dishonesty, breach of fiduciary obligation or intentional wrongdoing or misfeasance;
  - the employee has acted intentionally or in bad faith in a manner that results in a material detriment to the assets, business or prospects of Crosstex Energy GP, LLC; or
  - the employee has breached any obligation under the employment agreement.
- "Good reason" includes any of the following:
  - the assignment to employee of any duties materially inconsistent with the employee's position (including a materially adverse change in the employee's office, title and reporting requirements), authority, duty or responsibilities;
  - Crosstex Energy GP, LLC requiring the employee to be based at any office other than the offices in the greater Dallas, Texas area;
  - any termination by Crosstex Energy GP, LLC of the employee's employment other than as expressly permitted by the employment agreement; or
  - a breach or violation by Crosstex Energy GP, LLC of any material provision of the employment agreement, which breach or violation remains unremedied for more than 30 days after written notice thereof is given to Crosstex Energy GP, LLC by the employee.

  No act or failure to act on Crosstex Energy GP, LLC's part shall be considered "good reason" unless the employee has given Crosstex Energy GP, LLC written notice of such act or failure to act within 30 days thereof and Crosstex Energy GP, LLC fails to remedy such act or failure to act within 30 days of its receipt of such notice.

- A “change in control” shall be deemed to have occurred if:
  - Crosstex Energy, Inc. and/or its affiliates, collectively, no longer directly or indirectly hold a controlling interest in Crosstex Energy GP, L.P. or Crosstex Energy GP, LLC and the named executive officer does not remain employed by Crosstex Energy GP, LLC upon the occurrence of such event (whether the employee’s employment is terminated voluntarily or by Crosstex Energy GP, LLC);
  - the consummation of any transaction as a result of which any person (other than Yorktown Partners LLC, a Delaware limited liability company, or its affiliates including any funds under its management) becomes the “beneficial owner” (as defined in Rule 13d-3 under the Securities Exchange Act of 1934, as amended), directly or indirectly, of at least 50% of the total voting power represented by the outstanding voting securities of Crosstex Energy, Inc. at a time when Crosstex Energy, Inc. still beneficially owns 50% or more of the voting power of the outstanding equity interests of Crosstex Energy GP, L.P. or Crosstex Energy GP, LLC; or
  - Crosstex Energy GP, LLC has caused the sale of at least 50% of our assets.

If a termination of a named executive officer by Crosstex Energy GP, LLC other than for cause, a termination by a named executive officer for good reason or upon a change in control were to have occurred as of December 31, 2006, our named executive officers would have been entitled to the following:

- Barry E. Davis would have received $390,000 representing base salary for the remainder of the term of the employment agreement (i.e., one year’s salary paid at regularly scheduled times), $95,000 representing bonuses earned under any incentive plans in which he is a participant earned up to the date of termination or change in control and continued participation in Crosstex Energy GP, LLC’s health plans for the remainder of the term of the employment agreement;
- James R. Wales would have received $275,000 representing base salary for the remainder of the term of the employment agreement (i.e., one year’s salary paid at regularly scheduled times), $45,000 representing bonuses earned under any incentive plans in which he is a participant earned up to the date of termination or change in control and continued participation in Crosstex Energy GP, LLC’s health plans for the remainder of the term of the employment agreement;
- Robert S. Purgason would have received $275,000 representing base salary for the remainder of the term of the employment agreement (i.e., one year’s salary paid at regularly scheduled times), $47,500 representing bonuses earned under any incentive plans in which he is a participant earned up to the date of termination or change in control and continued participation in Crosstex Energy GP, LLC’s health plans for the remainder of the term of the employment agreement;
- Jack M. Lafield would have received $275,000 representing base salary for the remainder of the term of the employment agreement (i.e., one year’s salary paid at regularly scheduled times), $60,000 representing bonuses earned under any incentive plans in which he is a participant earned up to the date of termination or change in control and continued participation in Crosstex Energy GP, LLC’s health plans for the remainder of the term of the employment agreement; and
- William W. Davis would have received $275,000 representing base salary for the remainder of the term of the employment agreement (i.e., one year’s salary paid at regularly scheduled times), $60,000 representing bonuses earned under any incentive plans in which he is a participant earned up to the date of termination or change in control and continued participation in Crosstex Energy GP, LLC’s health plans for the remainder of the term of the employment agreement.

Crosstex Energy GP, LLC Long-Term Incentive Plan. Under current policy, if a grantee’s employment is terminated for any reason other than death or disability, depending on the particular terms of the agreement in question, a grantee’s unit options and restricted units granted under the long-term incentive plan may automatically be forfeited unless, and to the extent, the Compensation Committee provides otherwise. Upon a change in control of us or our general partner, all unit options and restricted units shall automatically vest and become payable or exercisable, as the case may be, in full and any restricted periods or performance criteria shall terminate or be deemed to have been achieved at the maximum level. For purposes of the long-term incentive plan, a "change in control" means, and shall be deemed to have occurred if:

- the consummation of a merger or consolidation of the Crosstex Energy GP, LLC with or into another entity or any other transaction if persons who were not holders of equity interests of Crosstex Energy GP, LLC immediately prior to such merger, consolidation or other transaction, 50% or more of the voting power of the outstanding equity interests of the continuing or surviving entity;
- the sale, transfer or other disposition of all or substantially all of Crosstex Energy GP, LLC's or our assets;
- a change in the composition of the board of directors as a result of which fewer than 50% of the incumbent directors are directors who either had been directors of Crosstex Energy GP, LLC on the date 12 months prior to the date of the event that may constitute a change in control (the "original directors") or were elected, or nominated for election, to the board of directors of Crosstex Energy GP, LLC with the affirmative votes of at least a majority of the aggregate of the original directors who were still in office at the time of the election or nomination and the directors whose election or nomination was previously so approved; or
- the consummation of any transaction as a result of which any person (other than Yorktown Partners LLC, a Delaware limited liability company, or its affiliates including any funds under its management) becomes the "beneficial owner" (as defined in Rule 13d-3 under the Exchange Act), directly or indirectly, of securities of Crosstex Energy, Inc. representing at least 50% of the total voting power represented by CEI's then outstanding voting securities at a time when Crosstex Energy, Inc. still beneficially owns more than 50% of securities of Crosstex Energy GP, LLC representing at least 50% of the total voting power represented by Crosstex Energy GP, LLC's then outstanding voting securities.

If a change in control were to have occurred as of December 31, 2006, unit options and restricted units held by the named executive officers would have automatically vested and become payable or exercisable, as follows:

- Barry E. Davis would have held 46,024 restricted units that would have become fully vested, payable and/or exercisable as a result of such change in control;
- James R. Wales would have held 25,042 restricted units that would have become fully vested, payable and/or exercisable as a result of such change in control;
- Robert S. Purgason would have held 23,172 restricted units and options to purchase 10,000 common units that would have become fully vested, payable and/or exercisable as a result of such change in control;
- Jack M. Lafield would have held 46,359 restricted units that would have become fully vested, payable and/or exercisable as a result of such change in control; and
- William W. Davis would have held 46,359 restricted units that would have become fully vested, payable and/or exercisable as a result of such change in control.

Crosstex Energy, Inc. Long-Term Incentive Plan. Immediately prior to a "change of control" of Crosstex Energy, Inc., all option awards and restricted stock awards automatically vest and become payable or exercisable, as the case may be, in full and all vesting periods with respect to restricted stock will terminate. . For purposes of the long-term incentive plan, a "change of control" means:

- the consummation of a merger or consolidation of Crosstex Energy, Inc. with or into another entity or any other transaction, if persons who were not shareholders of Crosstex Energy, Inc. immediately prior to such merger, consolidation or other transaction beneficially own immediately after such merger, consolidation or other transaction 50% or more of the voting power of the outstanding securities of each of (i) the continuing or surviving entity and (ii) any direct or indirect parent entity of such continuing or surviving entity;
- the sale, transfer or other disposition of all or substantially all of Crosstex Energy, Inc.'s assets;
- a change in the composition of the board of directors of Crosstex Energy, Inc. as a result of which fewer than 50% of the incumbent directors are directors who either (i) had been directors of Crosstex Energy, Inc. on the

date 12 months prior to the date of the event that may constitute a change of control (the “original directors”) or (ii) were elected, or nominated for election, to the board of directors of Crosstex Energy, Inc. with the affirmative votes of at least a majority of the aggregate of the original directors who were still in office at the time of the election or nomination and the directors whose election or nomination was previously so approved; or

- any transaction as a result of which any person is the “beneficial owner” (as defined in Rule 13d-3 under the Exchange Act), directly or indirectly, of securities of Crosstex Energy, Inc. representing at least 50% of the total voting power represented by Crosstex Energy, Inc.’s then outstanding voting securities.

If a change in control were to have occurred as of December 31, 2006, options and restricted stock held by the named executive officers would have automatically vested and become payable or exercisable, and any vesting periods of restricted stock would have terminated, as follows:

- Barry E. Davis would have held 75,654 shares of restricted stock that would have become fully vested, payable and/or exercisable as a result of such change in control;
- James R. Wales would have held 54,531 shares of restricted stock that would have become fully vested, payable and/or exercisable as a result of such change in control;
- Robert S. Purgason would have held 63,630 shares of restricted stock and options to purchase 30,000 shares of stock that would have become fully vested, payable and/or exercisable as a result of such change in control;
- Jack M. Lafield would have held 107,844 shares of restricted stock that would have become fully vested, payable and/or exercisable as a result of such change in control; and
- William W. Davis would have 107,844 shares of restricted stock that would have become fully vested, payable and/or exercisable as a result of such change in control.

Role of Executive Officers in Executive Compensation. Crosstex Energy GP, LLC’s Compensation Committee determines the compensation payable to each of the named executive officers as well as the compensation of members of its board of directors. None of the named executive officers serves as a member of the Compensation Committee. However, our chief executive officer, Barry E. Davis, provides periodic recommendations to the Compensation Committee regarding the compensation of the other named executive officers.

Tax and Accounting Considerations. The equity compensation grant policies of the Crosstex entities have been impacted by the implementation of SFAS No. 123R, which we adopted effective January 1, 2006. Under this accounting pronouncement, we are required to value unvested unit options granted prior to our adoption of SFAS 123 under the fair value method and expense those amounts in the income statement over the stock option’s remaining vesting period. As a result, the Crosstex entities currently intend to discontinue grants of unit option and stock option awards and instead grant restricted unit and restricted stock awards to the named executive officers and other employees. The Crosstex entities have structured the compensation program to comply with Internal Revenue Code Section 409A. If an executive is entitled to nonqualified deferred compensation benefits that are subject to Section 409A, and such benefits do not comply with Section 409A, then the benefits are taxable in the first year they are not subject to a substantial risk of forfeiture. In such case, the service provider is subject to regular federal income tax, interest and an additional federal income tax of 20% of the benefit includible in income. None of the named executive officers or other employees had non-performance based compensation paid in excess of the $1.0 million tax deduction limit contained in Internal Revenue Code Section 162(m).

Summary Compensation Table

The following table sets forth certain compensation information for our chief executive officer and the four other most highly compensated executive officers in 2006.

Name and Principal Position	Year	Salary ($)	Bonus ($)	Stock Awards ($)(6)	Option Awards ($)	Non-Equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($)	Total ($)
Barry E. Davis	2006	$ 390,000	$ 95,000	$ 1,126,875	—	—	—	$ 167,630(1)	$ 1,779,505
President and Chief Executive Officer									
William W. Davis	2006	275,000	60,000	685,926	—	—	—	198,061(2)	1,218,987
Executive Vice President and Chief Financial Officer									
Robert S. Purgason	2006	222,385	47,500	1,392,025	—	—	—	113,267(3)	1,775,177
Executive Vice President and Chief Operating Officer									
Jack M. Lafield	2006	275,000	60,000	685,926	—	—	—	198,061(4)	1,218,987
Executive Vice President									
James R. Wales	2006	275,000	45,000	538,919	—	—	—	105,022(5)	963,941
Executive Vice President									

(1) Amount of all other compensation for Mr. Barry Davis includes distributions on restricted units of Crosstex Energy, L.P. in the amount of $95,251 and dividends on restricted stock of Crosstex Energy, Inc. in the amount of $62,755.

(2) Amount of all other compensation for Mr. William Davis includes distributions on restricted units of Crosstex Energy, L.P. in the amount of $97,211 and dividends on restricted stock of Crosstex Energy, Inc. in the amount of $93,438.

(3) Amount of all other compensation for Mr. Purgason includes distributions on restricted units of Crosstex Energy, L.P. in the amount of $18,520 and dividends on restricted stock of Crosstex Energy, Inc. in the amount of $37,260. Mr. Purgason also received a monthly housing allowance of $4,476 per month.

(4) Amount of all other compensation for Mr. Lafield includes distributions on restricted units of Crosstex Energy, L.P. in the amount of $97,211 and dividends on restricted stock of Crosstex Energy, Inc. in the amount of $93,438.

(5) Amount of all other compensation for Mr. Wales includes distributions on restricted units of Crosstex Energy, L.P. in the amount of $52,914 and dividends on restricted stock of Crosstex Energy, Inc. in the amount of $49,484.

(6) The amounts shown represent the aggregate grant date fair value computed in accordance with Statement of Financial Accounting Standards No. 123R "Share-Based Payment."

Grants of Plan-Based Awards Table

The following tables provide information concerning each grant of an award made to a named executive officer during 2006, including, but not limited to, awards made under the Crosstex Energy GP, LLC Long-Term Incentive Plan and the Crosstex Energy, Inc. Long-Term Incentive Plan.

CROSSTEX ENERGY GP, LLC — GRANTS OF PLAN-BASED AWARDS

		Estimated Future Payouts Under Non-Equity Incentive Plan Awards			Estimated Future Payouts Under Equity Incentive Plan Awards			All Other Unit Awards: Number of Restricted Units	All Other Unit Awards: Number of Securities Underlying Options
Name	Grant Date	Threshold ($)	Target ($)	Maximum ($)	Threshold ($)	Target ($)	Maximum ($)	(#)	(#)
Barry E. Davis	04/12/2006	—	—	—	—	—	—	16,667	—
William W. Davis	04/12/2006	—	—	—	—	—	—	10,145	—
Robert S. Purgason	04/12/2006	—	—	—	—	—	—	5,797	—
	12/12/2006	—	—	—	—	—	—	13,089	—
Jack M. Lafield	04/12/2006	—	—	—	—	—	—	10,145	—
James R. Wales	04/12/2006	—	—	—	—	—	—	7,971	—

CROSSTEX ENERGY, INC. — GRANTS OF PLAN-BASED AWARDS

		Estimated Future Payouts Under Non-Equity Incentive Plan Awards			Estimated Future Payouts Under Equity Incentive Plan Awards			All Other Share Awards: Number of Restricted Shares	All Other Share Awards: Number of Securities Underlying Options
Name	Grant Date	Threshold ($)	Target ($)	Maximum ($)	Threshold ($)	Target ($)	Maximum ($)	(#)	(#)
Barry E. Davis	04/12/2006	—	—	—	—	—	—	7,718	—
William W. Davis	04/12/2006	—	—	—	—	—	—	4,698	—
Robert S. Purgason	04/12/2006	—	—	—	—	—	—	2,685	—
	12/12/2006	—	—	—	—	—	—	5,192	—
Jack M. Lafield	04/12/2006	—	—	—	—	—	—	4,698	—
James R. Wales	04/12/2006	—	—	—	—	—	—	3,691	—

Outstanding Equity Awards at Fiscal Year-End Table

The following tables provide information concerning all outstanding equity awards made to a named executive officer as of December 31, 2006, including, but not limited to, awards made under the Crosstex Energy GP, LLC Long-Term Incentive Plan and the Crosstex Energy, Inc. Long-Term Incentive Plan.

CROSSTEX ENERGY GP, LLC — OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END

	Option Awards					Stock Awards			
Name	Number of Securities Underlying Unexercised Options (#) Exercisable	Number of Securities Underlying Unexercised Options (#) Unexercisable	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#)	Option Exercise Price ($)	Option Expiration Date	Number of Units that have not Vested (#)	Market Value of Units that have not Vested ($)(1)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights that have not Vested (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights that have not Vested ($)
Barry E. Davis	—	—	—	—	—	46,024	1,834,056	—	—
William W. Davis	—	—	—	—	—	46,359	1,847,406	—	—
Robert S. Purgason	—	10,000	—	30.00	11/05/14	23,172	923,404	—	—
Jack M. Lafield	—	—	—	—	—	46,359	1,847,406	—	—
James R. Wales	—	—	—	—	—	25,042	997,924	—	—

(1) The closing price for the common units was $39.85 as of December 31, 2006.

CROSSTEX ENERGY, INC. — OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END

	Option Awards					Stock Awards			
Name	Number of Securities Underlying Unexercised Options (#) Exercisable	Number of Securities Underlying Unexercised Options (#) Unexercisable	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#)	Option Exercise Price ($)	Option Expiration Date	Number of Shares or Units of Stock That Have Not Vested (#)	Market Value of Shares or Units of Stock That Have Not Vested ($)(1)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)
Barry E. Davis	—	—	—	—	—	75,654	2,397,475	—	—
William W. Davis	—	—	—	—	—	107,844	3,417,576	—	—
Robert S. Purgason	—	30,000	—	13.33	12/07/14	63,630	2,016,434	—	—
Jack M. Lafield	—	—	—	—	—	107,844	3,417,576	—	—
James R. Wales	—	—	—	—	—	54,531	1,728,087	—	—

(1) The closing price for the common stock was $31.69 as of December 31, 2006.

Option Exercises and Units Vested Table

OPTION EXERCISES AND UNITS VESTED

	Option Awards		Unit Awards	
Name	Number of Units Acquired on Exercise (#)	Value Realized on Exercise ($)	Number of Units Acquired on Vesting (#)	Value Realized on Vesting ($)
Barry E. Davis	60,000	$ 1,575,000	5,500	$ 192,500
William W. Davis	—	—	3,500	122,500
Robert S. Purgason	—	—	—	—
Jack M. Lafield	35,000	918,750	3,500	122,500
James R. Wales	40,000	1,050,000	3,500	122,500

Compensation of Directors

DIRECTOR COMPENSATION

Name	Fees Earned or Paid in Cash ($)	Stock Awards ($)	Option Awards ($)	Non-Equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($)	Total ($)
Rhys J. Best	$ 108,042	$ 68,360	—	—	—	$ 2,180	$ 178,582
Frank M. Burke	83,208	68,360	—	—	—	2,180	153,748
James C. Crain	84,583	68,360	—	—	—	2,180	155,123
C. Roland Haden	9,167	—	—	—	—	—	9,167
Bryan H. Lawrence	—	—	—	—	—	—	—
Sheldon B. Lubar	64,845	68,360	—	—	—	2,180	135,385
Cecil E. Martin	73,833	68,360	—	—	—	2,180	144,373
Robert F. Murchison	70,958	68,360	—	—	—	2,180	141,498
Kyle D. Vann	68,333	68,360	—	—	—	2,180	138,873

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 $50,000. Directors do not receive an attendance fee for each regularly scheduled quarterly board meeting, but are paid $1,500 for each additional meeting that they attend. Also, an attendance fee of $1,500 is paid to each director for each committee meeting he attends. 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 executive officer of Crosstex Energy GP, LLC, is otherwise compensated for his services and therefore receives no separate compensation for his service as a director. For directors that serve on both the boards of Crosstex Energy GP, LLC and Crosstex Energy, Inc., the above listed fees are generally allocated 75% to us and 25% to Crosstex Energy, Inc.

Compensation Committee Interlocks and Insider Participation

During the fiscal year ended 2006, the Compensation Committee was composed of Sheldon B. Lubar, Robert F. Murchison and Rhys J. Best. No member of the Compensation Committee was an officer or employee of Crosstex Energy GP, LLC. None of Crosstex Energy GP, LLC's executive officers served on the board of directors or the compensation committee of any other entity, for which any officers of such other entity served either on Crosstex Energy GP, LLC's Board of Directors or Compensation Committee.

Compensation Committee Report

The Compensation Committee of Crosstex Energy GP, LLC held four meetings during fiscal year 2006. The Compensation Committee has reviewed and discussed the Compensation Discussion and Analysis with management. Based upon such review, the related discussions and such other matters deemed relevant and appropriate by the Compensation Committee, the Compensation Committee has recommended to the Board of Directors that the Compensation Discussion and Analysis be included in this Form 10-K.

Sheldon B. Lubar (Chairman)
Robert F. Murchison
Rhys J. Best

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

Crosstex Energy, L.P. Ownership

The following table shows the beneficial ownership of units of Crosstex Energy, L.P. as of February 16, 2007, 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.

Percentages reflected in the table are based upon a total of 21,982,035 common units, 4,668,000 subordinated units, and 12,829,650 senior subordinated series C units as of February 16, 2007.

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	Subordinated Series C Units Beneficially Owned	Percentage of Subordinated Series C Units Beneficially Owned	Percentage of Total Units Beneficially Owned
Crosstex Holdings, L.P.(2)	5,332,000	24.26%	4,668,000	100.0%	6,414,830	50.00%	41.58%
Chieftain Capital Management, Inc.(3)	—	—			2,851,030	22.22%	7.22%
Kayne Anderson Capital Advisors, L.P.(4)	3,314,591	15.08%	—	—	712,760	5.56%	10.20%
Tortoise Capital Advisors, LLC(5)	2,882,673	13.11%	—	—	712,760	5.56%	9.11%
Lehman Brothers Holdings Inc.(3)	313	*	—	—	1,496,790	11.67%	3.79%
Barry E. Davis(6)	35,870	*	—	—	—	—	*
William W. Davis(6)	4,574	*	—	—	—	—	*
Robert S. Purgason(6)	—	—	—	—	—	—	—
Jack M. Lafield(6)	2,365	*	—	—	—	—	*
James R. Wales(6)	24,666	*	—	—	—	—	*
Rhys J. Best	8,500	*	—	—	—	—	*
Frank M. Burke(6)	26,000	*	—	—	—	—	*
James A. Crain(6)	—	—	—	—	—	—	—
Bryan H. Lawrence(6)(7)	—	—	—	—	—	—	—
Sheldon B. Lubar(6)(8)	29,822	*	—	—	285,100	2.22%	*
Cecil E. Martin	—	—	—	—	—	—	—
Robert F. Murchison(6)(9)	78,281	*	—	—	—	—	*
Kyle D. Vann	—	—	—	—	—	—	—
All directors and executive officers as a group (16 persons)	238,691	1.09%	—	—	285,100	2.22%	1.33%

* Less than 1%.

(1) The address of each person listed above is 2501 Cedar Springs, Suite 100, Dallas, Texas 75201, except for Mr. Lawrence, which is 410 Park Avenue, New York, New York 10022; Kayne Anderson Capital Advisors, L.P., which is 1800 Avenue of the Stars, Second Floor, Los Angeles, California 90067; Tortoise Capital Advisors LLC, which is 10801 Martin Blvd., Ste 222, Overland Park, Kansas 66210; and Lehman Brothers Holdings, Inc., which is 745 7th Avenue, New York, New York 10019.

(2) Crosstex Holdings, L.P. is a wholly owned subsidiary of Crosstex Energy, Inc.

(3) As reported on Schedule 13G filed with the SEC.

(4) As reported on Schedule 13G filed with the SEC in a joint filing with Richard A. Kayne.

(5) As reported on Schedule 13G filed with the SEC in a joint filing with Tortoise Energy Capital Corporation (with respect to the Common Units) and Tortoise Energy Infrastructure Corporation (with respect to the Subordinated Series C Units).

(6) These individuals each hold an ownership interest in Crosstex Energy, Inc. as indicated in the following table.

(7) 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.

(8) Sheldon B. Lubar is a general partner of Lubar Nominees, which holds an ownership interest in Crosstex Energy, Inc. (as indicated in the following table). Mr. Lubar is also a director of the manager of Lubar Equity Fund, LLC, which holds an ownership interest in Crosstex Energy, Inc. (as indicated in the following table) and owns the 285,100 Subordinated Series C Units of Crosstex Energy, L.P.

(9) 48,459 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.

Crosstex Energy, Inc. Ownership

The following table shows the beneficial ownership of Crosstex Energy, Inc. as of February 16, 2007, held by:

- each person who beneficially owns 5% or more of the stock then outstanding;
- all the directors of Crosstex Energy, Inc.;
- each named executive officer of Crosstex Energy, Inc.; and
- all the directors and executive officers of Crosstex Energy, Inc. as a group.

Percentages reflected in the table below are based on a total of 45,998,923 shares of common stock outstanding as of February 16, 2007.

Name of Beneficial Owner (1)	Shares of Common Stock	Percent
Chieftain Capital Management, Inc.	8,395,103	18.25%
Yorktown Energy Partners IV, L.P.	1,745,319	3.79%
Yorktown Energy Partners V, L.P.	546,660	1.19%
Lubar Nominees(2)	2,092,494	4.55%
Lubar Equity Fund, LLC(2)	468,210	1.02%
Barry E. Davis	1,527,842	3.32%
William W. Davis	136,615	*
Robert S. Purgason(3)	600	*
Jack M. Lafield	126,600	*
James R. Wales	719,122	1.56%
Frank M. Burke(4)	37,500	*
James A. Crain	3,000	*
Bryan H. Lawrence(5)	1,542,396	3.35%
Sheldon B. Lubar(2)	17,433	*
Cecil E. Martin	—	*
Robert F. Murchison(6)	162,933	*
All directors and executive officers as a group (14 persons)	5,223,401	11.36%

* Less than 1%.

(1) The address of each person listed above is 2501 Cedar Springs, Suite 100, Dallas, Texas 75201, except for Chieftain Capital Management, Inc., which is 12 East 49th Street, New York, New York 10017, and Mr. Lawrence, Yorktown Energy Partners IV, L.P. and Yorktown Energy Partners V, L.P., which is 410 Park Avenue, New York, New York 10022.

(2) Sheldon B. Lubar is a general partner of Lubar Nominees and director of the manager of Lubar Equity Fund, LLC, and may be deemed to beneficially own the shares held by these entities.

(3) These shares are held by the M. I. Purgason Trust, of which Mr. Purgason serves as co-trustee.

(4) 15,000 of these shares are held by Burke Mayborn Co., Ltd., of which Mr. Burke is an owner and serves as a principal officer.

(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) 127,500 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.

Item 13. ***Certain Relationships and Related Transactions and Director Independence***

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.

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 5,332,000 common units, 4,668,000 subordinated units and 6,414,830 senior subordinated series C units representing approximately 42% 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 in us effectively gives our general partner the ability to veto some of our actions and to control our management. Crosstex Energy, Inc. pays us for administrative and compensation costs that we incur on its behalf. During 2006, this fee was approximately $40,000 per month.

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

Affiliates of a Major Shareholder in CEI. We treat gas for, and purchase gas from, Camden Resources, Inc. and treat gas for Erskine Energy Corporation and Approach Resources, Inc. All three entities are affiliates of us by way of equity investments made by Yorktown Energy Partners IV, L.P. and Yorktown Energy Partners V, L.P., collectively a major shareholder in CEI. The gas treating and gas purchase agreements we have entered into with these three entities are standard industry agreements containing terms substantially similar to those contained in our agreements with other third parties. During the year ended December 31, 2006, we purchased natural gas from Camden Resources, Inc. in the amount of approximately $32.5 million and received approximately $2.6 million in treating fees from Camden Resources, Inc. During the year ended December 31, 2006, we received treating fees of $1.3 million and $0.3 million from Erskine Energy Corporation and Approach Resources, Inc., respectively.

Purchase of Senior Subordinated Series C Units by Related Parties. On June 29, 2006, CEI purchased $180.0 million and Lubar Equity Fund, LLC purchased $8.0 million of our senior subordinated series C units issued in a private placement. The funds raised in the private offering were used to acquire the natural gas gathering pipeline systems and related facilities of Chief Holdings LLC. Mr. Sheldon B. Lubar is a member of the board of directors of Crosstex Energy GP, LLC and is a member of CEI's board and is also an affiliate of Lubar Equity Fund, LLC.

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 located 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.

Reimbursement of Costs by CEI. CEI paid us $0.5 million, $0.3 million and $0.4 million during the years ended December 31, 2006, 2005 and 2004, respectively, to cover its portion of administrative and compensation costs for officers and employees that perform services for CEI.

Approval and Review of Related Party Transactions. If we contemplate entering into a transaction, other than a routine or in the ordinary course of business transaction, in which a related person will have a direct or indirect material interest, the proposed transaction is submitted for consideration to the board of directors of Crosstex Energy GP, LLC or to our senior management, as appropriate. If the board of directors is involved in the approval process, it determines whether it is advisable to refer the matter to the Conflicts Committee, as constituted under the limited partnership agreement of Crosstex Energy, L.P. If a matter is referred to the Conflicts Committee, the Conflicts Committee obtains information regarding the proposed transaction from management and determines whether it is advisable to engage independent legal counsel or an independent financial advisor to advise the members of the committee regarding the transaction. If the Conflicts Committee retains such counsel or financial advisor, it considers the advice and, in the case of a financial advisor, such advisor's opinion as to whether the transaction is fair and reasonable to us and to our unitholders. The purchase of the senior subordinated series C units described above was approved by the Conflicts Committee.

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, 2007.

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, 2006 and December 31, 2005, review of our internal control procedures for the fiscal year ended December 31, 2006 and December 31, 2005, 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 $1.5 million and $1.2 million, 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, 2006 and December 31, 2005 that were not included in the audit fees listed above.

Tax Fees

We did not incur any fees by KPMG for tax compliance, tax advice and tax planning for the years ended December 31, 2006 and December 31, 2005.

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, 2006 and December 31, 2005.

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 2007, 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-41.

(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	—	Fifth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of June 29, 2005 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated June 29, 2006, filed with the Commission on July 6, 2006).
3.3	—	Certificate of Limited Partnership of Crosstex Energy Services, L.P. (incorporated by reference to Exhibit 3.3 to our Registration Statement on Form S-1, file No. 333-97779).
3.4	—	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).
3.5	—	Certificate of Limited Partnership of Crosstex Energy GP, L.P. (incorporated by reference to Exhibit 3.5 to our Registration Statement on Form S-1, file No. 333-97779).
3.6	—	Agreement of Limited Partnership of Crosstex Energy GP, L.P., dated as of July 12, 2002 (incorporated by reference to Exhibit 3.6 to our Registration Statement on Form S-1, file No. 333-97779).

Number		Description
3.7	—	Certificate of Formation of Crosstex Energy GP, LLC (incorporated by reference to Exhibit 3.7 to our Registration Statement on Form S-1, file No. 333-97779).
3.8	—	Amended and Restated Limited Liability Company Agreement of Crosstex Energy GP, LLC, dated as of December 17, 2002 (incorporated by reference to Exhibit 3.8 to our Registration Statement on Form S-1, file No. 333-97779).
4.1	—	Specimen Unit Certificate for Common Units (incorporated by reference to Exhibit 4.7 to Amendment No. 1 to our Registration Statement on Form S-3, file No. 333-128282).
4.2	—	Specimen Unit Certificate for the Senior Subordinated Series C Units (incorporated by reference to Exhibit 4.8 to our Registration Statement on Form S-3, file No. 333-135951).
4.3	—	Registration Rights Agreement, dated as of November 1, 2005, by and among Crosstex Energy, L.P., Kayne Anderson MLP Investment Company, Kayne Anderson Energy Total Return Fund, Inc., Tortoise Energy Capital Corp., Tortoise Energy Infrastructure Corporation and Fiduciary/Claymore MLP Opportunity Fund (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated November 1, 2005, filed with the Commission on November 3, 2005).
4.4	—	Registration Rights Agreement, dated as of June 24, 2005, among Crosstex Energy, L.P., Kayne Anderson MLP Investment Company, Tortoise Energy Capital Corporation and Tortoise Energy Infrastructure Corporation (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated June 24, 2005, filed with the Commission on June 4, 2005).
4.6	—	Registration Rights Agreement, dated as of June 29, 2006, by and among Crosstex Energy L.P., Chieftain Capital Management, Inc., Energy Income and Growth Fund, Fiduciary/Claymore MLP Opportunity Fund, Kayne Anderson MLP Investment Company, Kayne Anderson Energy Total Return Fund, Inc., LBI Group Inc., Tortoise Energy Infrastructure Corporation, Lubar Equity Fund, LLC and Crosstex Energy, Inc. (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated June 29, 2006, filed with the Commission on July 6, 2006).
10.1	—	Fourth Amended and Restated Credit Agreement, dated November 1, 2005, among Crosstex Energy Services, L.P., Bank of America, N.A. and certain other parties (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated November 1, 2005, filed with the Commission on November 3, 2005).
10.2	—	First Amendment to Fourth Amended and Restated Credit Agreement, dated as of February 24, 2006, among Crosstex Energy, L.P., Bank of America, N.A. and certain other parties (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K dated March 13, 2006, filed with the Commission on March 16, 2006).
10.3	—	Second Amendment to Fourth Amended and Restated Credit Agreement, dated as of June 29, 2006, among Crosstex Energy, L.P., Bank of America, N.A. and certain other parties (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated June 29, 2006, filed with the Commission on July 6, 2006).
10.4	—	Amended and Restated Note Purchase Agreement, dated as of July 25, 2006, among Crosstex Energy, L.P. and the Purchasers listed on the Purchaser Schedule attached thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated July 25, 2006, filed with the Commission on July 28, 2006).
10.5	—	Purchase and Sale Agreement, dated as of May 1, 2006, by and between Crosstex Energy Services, L.P., Chief Holdings LLC and the other parties named therein (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated May 1, 2006, filed with the Commission on May 4, 2006).
10.6†	—	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).
10.7	—	Amendment to Crosstex Energy GP, LLC Long-Term Incentive Plan, dated May 2, 2005 (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated May 2, 2005, filed with the Commission on May 6, 2005).
10.8	—	Omnibus Agreement, dated December 17, 2002, among Crosstex Energy, L.P. and certain other parties (incorporated by reference to Exhibit 10.5 to our Annual Report on Form 10-K for the year ended December 31, 2002).

Number		Description
10.9†	—	Form of Employment Agreement (incorporated by reference to Exhibit 10.6 to our Annual Report on Form 10-K for the year ended December 31, 2002).
10.10	—	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).
10.11	—	Senior Subordinated Series C Unit Purchase Agreement, dated as of May 16, 2006, by and among Crosstex Energy, L.P. and each of the Purchasers set forth on Schedule A thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated May 16, 2006, filed with the Commission on May 17, 2006).
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 28th day of February 2007.

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)	February 28, 2007
/s/ RHYS J. BEST Rhys J. Best	Director	February 28, 2007
/s/ FRANK M. BURKE Frank M. Burke	Director	February 28, 2007
/s/ JAMES A. CRAIN James A. Crain	Director	February 28, 2007
/s/ BRYAN H. LAWRENCE Bryan H. Lawrence	Chairman of the Board	February 28, 2007
/s/ SHELDON B. LUBAR Sheldon B. Lubar	Director	February 28, 2007
/s/ CECIL E. MARTIN Cecil E. Martin	Director	February 28, 2007
/s/ ROBERT F. MURCHISON Robert F. Murchison	Director	February 28, 2007
/s/ KYLE D. VANN Kyle D. Vann	Director	February 28, 2007
/s/ WILLIAM W. DAVIS William W. Davis	Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	February 28, 2007

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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, 2006, 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, 2006, 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.

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 page F-4 of this Annual Report on Form 10-K.

Report of Independent Registered Public Accounting Firm

The Partners
Crosstex Energy, L.P.:

We have audited the accompanying consolidated balance sheets of Crosstex Energy, L.P. (a Delaware limited partnership) and subsidiaries as of December 31, 2006 and 2005 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, 2006. 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, 2006 and 2005 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, 2006, 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.

As discussed in Note 2 to the consolidated financial statements, effective January 1, 2006, Crosstex Energy, L.P. and subsidiaries adopted the provisions of Statement of Financial Accounting Standards No. 123 (revised 2004), *Share Based Payment.*

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, 2006, 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 February 28, 2007, expressed an unqualified opinion on management's assessment of, and the effective operation of, internal control over financial reporting.

/s/ KPMG LLP

Dallas, Texas
February 28, 2007

Report of Independent Registered Public Accounting Firm

The Partners
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. and subsidiaries (a Delaware limited partnership) maintained effective internal control over financial reporting as of December 31, 2006, 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 conducted 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. and subsidiaries maintained effective internal control over financial reporting as of December 31, 2006, 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, 2006, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations (COSO).

We also have audited, in accordance with the standards of the Public Company Accounting and Oversight Board (United States), the consolidated balance sheets of Crosstex Energy, L.P. and subsidiaries as of December 31, 2006 and 2005 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, 2006, and our report dated February 28, 2007 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Dallas, Texas
February 28, 2007

CROSSTEX ENERGY, L.P.

Consolidated Balance Sheets
December 31, 2006 and 2005

	December 31, 2006	December 31, 2005
	(In thousands except unit data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 824	$ 1,405
Accounts receivable:		
Trade, net of allowance for bad debts of $618 and $260, respectively	35,787	60,009
Accrued revenues	331,236	368,860
Imbalances	5,159	7,833
Affiliated companies	23	173
Note receivable	926	845
Other	2,864	4,896
Fair value of derivative assets	23,048	12,205
Natural gas and natural gas liquids, prepaid expenses, and other	10,468	23,549
Total current assets	410,335	479,775
Property and equipment:		
Transmission assets	335,599	194,235
Gathering systems	285,706	36,653
Gas plants	460,774	389,083
Other property and equipment	30,816	26,283
Construction in process	129,373	98,093
Total property and equipment	1,242,268	744,347
Accumulated depreciation	(136,455)	(77,205)
Total property and equipment, net	1,105,813	667,142
Fair value of derivative assets	3,812	7,633
Intangible assets, net of accumulated amortization of $31,673 and $7,674, respectively	638,602	255,197
Goodwill	24,495	6,568
Other assets, net	11,417	8,843
Total assets	2,194,474	$ 1,425,158
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Drafts payable	$ 47,948	$ 29,855
Accounts payable	31,764	16,567
Accrued gas purchases	325,151	360,458
Accrued imbalances payable	2,855	30,515
Accrued construction in process costs	29,942	10,545
Fair value of derivative liabilities	12,141	14,782
Current portion of long-term debt	10,012	6,521
Other current liabilities	30,458	22,213
Total current liabilities	490,271	491,456
Long-term debt	977,118	516,129
Deferred tax liability	8,996	8,437
Minority interest	3,654	4,274
Fair value of derivative liabilities	2,558	3,577
Commitments and contingencies	—	—
Partners' equity:		
Common unitholders (19,616,172 and 15,465,528 units issued and outstanding at December 31, 2006 and 2005, respectively)	330,492	326,617
Subordinated unitholders (7,001,000 and 9,334,000 units issued and outstanding at December 31, 2006 and 2005, respectively)	(6,402)	16,462
Senior subordinated unitholders (1,495,410 units issued and outstanding at December 31, 2005)	—	49,921
Senior subordinated C unitholders (12,829,650 units issued and outstanding at December 31, 2006)	359,319	—
General partner interest (2% interest with 805,037 and 536,631 equivalent units outstanding at December 31, 2006 and 2005, respectively)	20,472	11,522
Accumulated other comprehensive income	7,996	(3,237)
Total partners' equity	711,877	401,285
Total liabilities and partners' equity	$ 2,194,474	$ 1,425,158

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Operations

	Years Ended December 31, 2006	2005	2004
	(In thousands except per unit data)		
Revenues:			
Midstream	$ 3,073,069	$ 2,982,874	$ 1,948,021
Treating	66,225	48,606	30,755
Profit on energy trading activities	2,510	1,568	2,228
Total revenues	3,141,804	3,033,048	1,981,004
Operating costs and expenses:			
Midstream purchased gas	2,859,815	2,860,823	1,861,204
Treating purchased gas	9,463	9,706	5,274
Operating expenses	100,991	56,736	38,340
General and administrative	45,694	32,697	20,866
(Gain) loss on derivatives	(1,599)	9,968	(279)
Gain on sale of property	(2,108)	(8,138)	(12)
Depreciation and amortization	82,731	36,024	23,034
Total operating costs and expenses	3,094,987	2,997,816	1,948,427
Operating income	46,817	35,232	32,577
Other income (expense):			
Interest expense, net of interest income	(51,427)	(15,767)	(9,220)
Other income	183	392	798
Total other income (expense)	(51,244)	(15,375)	(8,422)
Income (loss) before minority interest and taxes	(4,427)	19,857	24,155
Minority interest in subsidiary	(231)	(441)	(289)
Income tax provision	(222)	(216)	(162)
Net income (loss) before cumulative effect of change in accounting principle	(4,880)	19,200	23,704
Cumulative effect of change in accounting principle	689	—	—
Net income (loss)	$ (4,191)	$ 19,200	$ 23,704
General partner interest in net income (loss)	$ 16,456	$ 8,652	$ 5,913
Limited partners' interest in net income (loss)	$ (20,647)	$ 10,548	$ 17,791
Net income (loss) before cumulative effect of change in accounting principle per limited partners' unit:			
Basic	$ (0.81)	$ 0.56	$ 0.98
Diluted	$ (0.81)	$ 0.51	$ 0.95
Cumulative effect of change in accounting principle per limited partners' unit:			
Basic	$ 0.03	—	—
Diluted	$ 0.03	—	—
Net income (loss) per limited partners' unit:			
Basic	$ (0.78)	$ 0.56	$ 0.98
Diluted	$ (0.78)	$ 0.51	$ 0.95
Weighted average limited partners' units outstanding:			
Basic	26,337	19,006	18,081
Diluted	26,337	20,527	18,633

See accompanying notes to consolidated financial statements.

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CROSSTEX ENERGY, L.P.

Consolidated Statements of Changes in Partners' Equity
Years ended December 31, 2006, 2005 and 2004

	Common Units		Subordinated Units		Sr. Subordinated Units		Sr. Subordinated C Units		General Partner Interest		Accumulated Other Comprehensive Income	Total
	$	Units	$	Units	$	Units	$	Units	$	Units		
						(Unaudited) (In thousands, except unit amounts)						
Balance, December 31, 2003	$ 116,780	8,716,000	$ 33,593	9,334,000	—	—	—	—	$ 2,854	368,367	$ 1,383	$ 154,610
Proceeds from exercise of common unit options	425	39,066	—	—	—	—	—	—	—	798	—	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	8,755,066	28,002	9,334,000	—	—	—	—	4,078	369,165	10	144,050
Net proceeds from issuance of common units(1)	223,340	6,581,215	—	—	—	—	—	—	—	—	—	223,340
Net proceeds from issuance of senior subordinated units	—	—	—	—	49,921	1,495,410	—	—	—	—	—	49,921
Proceeds from exercise of common unit options	1,345	129,247	—	—	—	—	—	—	—	—	—	1,345
Capital contributions	—	—	—	—	—	—	—	—	6,311	167,466	—	6,311
Stock-based compensation	1,798	—	—	—	—	—	—	—	1,874	—	—	3,672
Distributions	(16,459)	—	(17,455)	—	—	—	—	—	(9,393)	—	—	(43,307)
Net income	4,633	—	5,915	—	—	—	—	—	8,652	—	—	19,200
Hedging gains or losses reclassified to earnings	—	—	—	—	—	—	—	—	—	—	7,864	7,864
Adjustment in fair value of derivatives	—	—	—	—	—	—	—	—	—	—	(11,111)	(11,111)
Balance, December 31, 2005	326,617	15,465,528	16,462	9,334,000	49,921	1,495,410	—	—	11,522	536,631	(3,237)	401,285
Proceeds from exercise of unit options	3,328	304,936	—	—	—	—	—	—	—	—	—	3,328
Net proceeds from issuance of senior subordinated C units	—	—	—	—	—	—	359,319	12,829,650	—	—	—	359,319
Conversion of subordinated units	52,195	3,828,410	(2,274)	(2,333,000)	(49,921)	(1,495,410)	—	—	—	—	—	—
Conversion of common units for restricted units	—	17,298	—	—	—	—	—	—	—	—	—	—
Capital contributions	—	—	—	—	—	—	—	—	9,273	268,406	—	9,273
Stock-based compensation	3,122	—	1,114	—	—	—	—	—	3,632	—	—	7,868
Distributions	(39,725)	—	(16,102)	—	—	—	—	—	(20,411)	—	—	(76,238)
Net income (loss)	(15,045)	—	(5,602)	—	—	—	—	—	16,456	—	—	(4,191)
Hedging gains or losses reclassified to earnings	—	—	—	—	—	—	—	—	—	—	(4,875)	(4,875)
Adjustment in fair value of derivatives	—	—	—	—	—	—	—	—	—	—	16,108	16,108
Balance, September 30, 2006	$ 330,492	19,616,172	$ (6,402)	7,001,000	$ —	—	$ 359,319	12,829,650	$ 20,472	805,037	$ 7,996	$ 711,877

(1) Includes Senior Subordinated Series B Units which automatically converted to common units fourteen days after issuance. See Note 6(a).

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Comprehensive Income

	December 31, 2006	2005	2004
		(In thousands)	
Net income (loss)	$ (4,191)	$ 19,200	$ 23,704
Hedging gains or losses reclassified to earnings	(4,875)	7,864	(4,015)
Adjustment in fair value of derivatives	16,108	(11,111)	2,642
Comprehensive income	$ 7,042	$ 15,953	$ 22,331

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Cash Flows

	Years Ended December 31, 2006	2005	2004
	(In thousands)		
Cash flows from operating activities:			
Net income (loss)	$ (4,191)	$ 19,200	$ 23,704
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Depreciation and amortization	82,731	36,024	23,034
Gain on sale of property	(2,108)	(8,138)	(12)
Cumulative effect of change in accounting principle	(689)	—	—
Minority interest in earnings	231	441	289
Deferred tax expense (benefit)	490	216	(190)
Loss on investment in affiliated partnerships	—	—	(304)
Non-cash stock-based compensation	8,557	3,672	1,001
Amortization of debt issue costs	2,694	1,127	1,016
Non-cash derivatives (gain) loss	550	10,208	(279)
Changes in assets and liabilities, net of acquisition effects:			
Accounts receivable and accrued revenue	77,418	(165,990)	(47,604)
Natural gas storage, prepaid expenses and other	13,071	(1,719)	(2,682)
Accounts payable, accrued gas purchases and other accrued liabilities	(65,691)	132,932	50,676
Fair value of derivatives	—	(13,963)	(473)
Other	(53)	—	(73)
Net cash provided by operating activities	113,010	14,010	48,103
Cash flows from investing activities:			
Additions to property and equipment	(314,766)	(120,490)	(45,984)
Acquisitions and asset purchases	(576,110)	(505,518)	(78,895)
Proceeds from sales of property	5,051	10,991	611
Additions to other non-current assets	—	—	(115)
Distributions from (investments in) affiliated partnerships	—	—	12
Net cash used in investing activities	(885,825)	(615,017)	(124,371)
Cash flows from financing activities:			
Proceeds from borrowings	1,708,500	1,798,250	491,500
Payments on borrowings	(1,244,021)	(1,424,300)	(403,550)
Increase (decrease) in drafts payable	18,094	(8,812)	28,221
Debt refinancing costs	(5,646)	(6,919)	(1,370)
Distributions to minority interest party	(375)	786	990
Distribution to partners	(76,238)	(43,307)	(34,317)
Proceeds from exercise of unit options	3,328	1,345	425
Net proceeds from common unit offerings	—	223,340	—
Net proceeds from issuance of subordinated units	359,319	49,915	—
Contribution from partners	9,273	6,317	—
Net cash provided by financing activities	772,234	596,615	81,899
Net increase (decrease) in cash and cash equivalents	(581)	(4,392)	5,631
Cash and cash equivalents, beginning of period	1,405	5,797	166
Cash and cash equivalents, end of period	$ 824	$ 1,405	$ 5,797
Cash paid for interest	$ 46,794	$ 14,598	$ 7,556
Cash paid for income taxes	$ (847)	$ 496	$ 380

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements

(1) Organization and Summary of Significant Agreements

(a) Description of Business

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

(b) Partnership Ownership

Crosstex Energy GP, L.P., the general partner of the Partnership, is wholly-owned by Crosstex Energy, Inc. (CEI). As of December 31, 2006, CEI also owns 7,001,000 subordinated units, 6,414,830 senior subordinated series C units and 2,999,000 common units in the Partnership through its wholly-owned subsidiaries. As of December 31, 2006, CEI owned 42.0% of the limited partner interests in the Partnership and officers and directors owned 0.8% of the limited partnership interests. The remaining units are held by the public. As of December 31, 2006, Yorktown Energy Partners IV, L.P. and Yorktown Energy Partners V, L.P. (collectively, Yorktown) owned 5.0% of CEI and CES management and directors owned 14.2% of CEI.

In February 2007 2,333,000 of CEI's subordinated units converted to common units so that the current ownership of subordinated units is 4,668,000 and common units is 5,332,000.

(c) Basis of Presentation

The accompanying consolidated financial statements include the assets, liabilities, and results of operations of the Partnership and its wholly-owned subsidiaries. The Partnership proportionately consolidates its undivided 12.4% interest in a carbon dioxide processing plant acquired by the Partnership in June 2004 and its undivided 59.27% interest in a gas plant acquired by the Partnership in November 2005 (23.85%) and May 2006 (35.42%). 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. (CDC) 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.

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements — (Continued)

(c) Natural Gas and Natural Gas Liquids Inventory

The Partnership's inventories of products consist of natural gas and natural gas liquids. The Partnership reports these assets at the lower of cost or market.

(d) Property, Plant, and Equipment

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

Other property and equipment is primarily comprised of computer software and equipment, furniture, fixtures, leasehold improvements and office equipment. 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. Interest costs are capitalized to property, plant and equipment during the period the assets are undergoing preparation for intended use. Interest costs totaling $5.4 million and $0.9 million were capitalized for the years ended December 31, 2006 and 2005, respectively. No interest costs were capitalized in 2004.

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

Depreciation expense of $68.9 million, $31.7 million and $21.8 million was recorded for the years ended December 31, 2006, 2005 and 2004, respectively.

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. No impairments were incurred during the three-year period ended December 31, 2006.

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 could require us to record an impairment of an asset.

(e) Goodwill and Intangibles

The Partnership has approximately $24.5 million and $6.6 million of goodwill at December 31, 2006 and 2005, respectively. During the formation of the Partnership in May 2001, $5.4 million of goodwill was created and later amortized by $0.5 million. Approximately $1.7 million and $1.4 million of goodwill resulted from the two Cardinal acquisitions in May 2005 and October 2006, respectively. Approximately $16.5 million of goodwill resulted from the Hanover acquisition in February 2006. The goodwill related to the formation of the Partnership has been allocated to the Midstream segment and the goodwill resulting from the Cardinal and Hanover acquisitions is allocated to the Treating segment. Goodwill is assessed at least annually for impairment. During the fourth quarter of 2006, the Partnership completed the annual impairment testing of goodwill and no impairment was incurred.

Intangible assets consist of customer relationships and the value of the dedicated and non-dedicated acreage attributable to pipeline, gathering and processing systems. The El Paso acquisition, as discussed in Note (3), included $254.0 million of such intangibles. The Chief acquisition, as discussed in Note (3), included $396.0 million of such intangibles, including the Devon Energy Corporation (Devon) gas gathering agreement. Intangible assets other than the intangibles associated with the Chief acquisition are amortized on a straight-line basis over the expected period of benefits of the customer relationships, which range from three to 15 years. The intangible assets associated with the Chief acquisition are being amortized using the units of throughput method of amortization.

The weighted average amortization period for intangible assets is 17.7 years. Amortization of intangibles was approximately $13.9 million, $4.3 million and $1.2 million for the years ended December 31, 2006, 2005 and 2004, respectively.

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

2007	$ 29,702
2008	37,513
2009	42,462
2010	45,758
2011	47,558
Thereafter	435,609
Total	$ 638,602

(f) Other Assets

Unamortized debt issuance costs totaling $11.4 million and $8.4 million as of December 31, 2006 and 2005, respectively, are included in other noncurrent assets. Debt issuance costs are amortized into interest expense using the effective-interest method over the term of the debt for the senior secured notes. Debt issuance costs are amortized using the straight-line method over the term of the debt for the bank credit facility because borrowings under the bank credit facility cannot be forecasted for an effective-interest computation. Other assets as of December 31, 2005 also included the noncurrent portion of the note receivable of $0.4 million from RLAC Gathering Group, L.P., the minority interest partner in the CDC joint venture discussed in Note 4.

(g) 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 imbalance payables of $2.9 million and $30.5 million at December 31, 2006 and 2005, respectively, which approximate the fair value of these imbalances. The Partnership had imbalance receivables of $5.2 million and $7.8 million at December 31, 2006 and 2005, respectively, which are carried at the lower of cost or market value.

(h) Asset Retirement Obligations

In March 2005, the FASB issued Interpretation No. 47, *"Accounting for Conditional Asset Retirement Obligations"* (FIN 47) which became effective at December 31, 2005. FIN 47 clarifies that the term "conditional asset retirement obligation" as used in FASB Statement No. 143, *"Accounting for Asset Retirement Obligations"*, refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Since the obligation to perform the asset retirement activity is unconditional, FIN 47 provides that a liability for the fair value of a conditional asset retirement activity should be recognized if that fair value can be reasonably estimated, even though uncertainty exists about the timing and/or method of settlement. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation under FASB Statement No. 143. The Partnership did not provide any asset retirement obligations as of December 31, 2006 or 2005 because it does not have sufficient information as set forth in FIN 47 to reasonably estimate such obligations and the Partnership has no current intention of discontinuing use of any significant assets.

(i) 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. The Partnership generally accrues one to two months of sales and the related gas purchases and reverses these accruals when the sales and purchases are actually invoiced and recorded in the subsequent months. Actual results could differ from the accrual estimates. See discussion of accounting for energy trading activities in note 2(k).

The Partnership accounts for taxes collected from customers attributable to revenue transactions and remitted to government authorities on a net basis (excluded from revenues).

(j) 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.

The Partnership recognizes all derivative and hedging instruments in the statements of financial position as either assets or liabilities and measures them at fair value in accordance with Statement of Financial Accounting Standards No. 133 (SFAS No. 133), *Accounting for Derivative Instruments and Hedging Activities.* 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 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.

(k) Energy Trading Activities

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 its energy trading activities. 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 energy trading 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. 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 energy trading activities. Accordingly, any gain or loss associated with changes in the fair value of derivatives and physical delivery contracts relating to the Partnership's energy trading activities are recognized in earnings as gain or loss on derivatives 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 gain or loss on derivatives in the statements of operations.

Net margins earned on settled contracts from its commercial services activities included in profit on energy trading activities in the consolidated statement of operations was $2.5 million, $1.6 million and $2.2 million for the years ended December 31, 2006, 2005 and 2004, respectively.

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

	Years Ended December 31,		
	2006	2005	2004
Volumes purchased and sold	50,563,000	66,065,000	76,576,000

(l) Comprehensive Income (Loss)

Comprehensive income includes net income (loss) 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 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.

(m) Legal Costs Expected to be Incurred in Connection with a Loss contingency

Legal costs incurred in connection with a loss contingency are expensed as incurred.

(n) 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 $205.3 million as of December 31, 2006. Effective January 1, 2007, the Partnership will be subject to the gross margin tax enacted by the state of Texas on May 1, 2006. The new tax law had no significant impact on the Partnership's deferred tax liability.

The 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. A deferred tax liability of $8.2 million 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, through ownership of the LIG entities, generated a net operating loss of $4.8 million during 2005 as a result of a tax loss on a property sale of which $0.9 million was carried back to 2004, $1.9 million was utilized in 2006 and substantially all of the remaining $2.0 million will be utilized in 2007.

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).

	2006	2005	2004
Current tax provision (benefit)	$ (268)	—	$ 352
Deferred tax provision (benefit)	490	$ 216	(190)
	$ 222	$ 216	$ 162
A reconciliation of the provision for income taxes for the taxable corporation is as follows (in thousands):			
Federal income tax on taxable corporation at statutory rate (35%)	$ 206	$ 206	$ 154
State income taxes, net	16	10	8
Tax provision (benefit)	$ 222	$ 216	$ 162

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

	December 31, 2006	December 31, 2005
Deferred income tax assets:		
Net operating loss carryforward — current	$ 718	$ 712
Net operating loss carryforward — long-term	49	1,062
Alternative minimum tax credit carryover — long-term	59	—
	$ 826	$ 1,774
Deferred income tax liabilities:		
Property, plant, equipment, and intangible assets-current	$ (501)	$ (496)
Property, plant, equipment and intangible assets-long-term	(9,103)	(9,499)
	$ (9,604)	$ (9,995)
Net deferred tax liability	$ (8,778)	$ (8,221)

A net current deferred tax asset of $0.7 million is included in other assets.

(o) 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. The Partnership records reserves for uncollectible accounts on a specific identification basis since there is not a large volume of late paying customers. The Partnership had a reserve for uncollectible receivables as of December 31, 2006 and 2005 of $0.6 million and $0.3 million, respectively.

During 2006 and 2005, Dow Hydrocarbons accounted for 13.4% and Formosa Hydrocarbons account for 10.6%, respectively, of the consolidated revenue of the Partnership. During 2004, Kinder Morgan accounted for 10.2% of the consolidated revenue of the Partnership. As the Partnership continues to grow and expand, this relationship between individual customer sales and consolidated total sales is expected to continue to change. While these customers represent a significant percentage of revenues, the loss of either would not have a material adverse impact on the Partnership results of operations.

(p) 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, 2006, 2005 and 2004, such expenditures were not significant.

(q) Option Plans

Effective January 1, 2006, the Partnership adopted the provisions of SFAS No. 123R, *"Share-Based Payment"* (FAS No. 123R) which requires compensation related to all stock-based awards, including stock options, be recognized in the consolidated financial statements. The Partnership applied the provisions of Accounting Principles Board Opinion No. 25, *"Accounting for Stock Issued to Employees"* (APB No. 25), for periods prior to January 1, 2006. In accordance with APB No. 25 for fixed stock and unit options, compensation expense was recorded prior to 2006 to the extent the market value of the stock or unit exceeded the exercise price of the option at the measurement date. Compensation expense for fixed awards with pro rata vesting was recognized on a straight-line basis over the vesting period. In addition, compensation expense was 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.

The Partnership elected to use the modified-prospective transition method for adopting SFAS No. 123R. Under the modified-prospective method, awards that are granted, modified, repurchased, or canceled after the date of adoption are measured and accounted for under SFAS No. 123R. The unvested portion of awards that were granted prior to the effective date are also accounted for in accordance with SFAS No. 123R. The Partnership adjusted compensation cost for actual forfeitures as they occurred under APB No. 25 for periods prior to January 1, 2006. Under SFAS No. 123R, the Partnership is required to estimate forfeitures in determining periodic compensation cost. The cumulative effect of the adoption of SFAS No. 123R recognized on January 1, 2006 was an increase in net income of $0.7 million due to the reduction in previously recognized compensation costs associated with the estimation of forfeitures.

The Partnership and CEI each have similar unit or share-based payment plans for employees, which are described below. Share-based compensation associated with the CEI share-based compensation plans awarded to officers and employees of the Partnership are recorded by the Partnership since CEI has no operating activities other than its interest in the Partnership. Amounts recognized in the consolidated financial statements with respect to these plans are as follows (in thousands):

	Years Ended December 31, 2006	2005	2004
Cost of share-based compensation charged to general and administrative expense	$ 7,426	$ 3,659	$ 802
Cost of share-based compensation charged to operating expense	1,131	398	199
Total amount charged to income before cumulative effect of accounting change	$ 8,557	$ 4,057	$ 1,001

Share-based compensation expense recorded in 2005 included $0.5 million related to the accelerated vesting of 7,060 common unit options and 10,000 CEI common share options.

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* for the years ended December 31, 2005 and 2004, the Partnership's net income (loss) would have been as follows (in thousands except per unit amounts):

	Years Ended December 31, 2005	2004
Net income, as reported	$ 19,200	$ 23,704
Add: Stock-based employee compensation expense included in reported net income	4,057	1,001
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards	(4,445)	(1,228)
Pro forma net income	$ 18,812	$ 23,477

	Years Ended December 31, 2005	2004
Net income per limited partner unit, as reported:		
Basic	$ 0.56	$ 0.98
Diluted	$ 0.51	$ 0.95
Pro forma net income per limited partner unit:		
Basic	$ 0.53	$ 0.97
Diluted	$ 0.50	$ 0.95

The fair value of each option is estimated on the date of grant using the Black Scholes option-pricing model as disclosed in Note (8) — Employee Incentive Plans.

(r) Recent Accounting Pronouncements

In June 2006, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 48 (FIN 48), "*Accounting for Uncertainty in Income Taxes*". FIN 48 is an interpretation of FASB Statement No. 109, "*Accounting for Income Taxes*" and must be adopted by the Partnership no later than January 1, 2007. FIN 48 prescribes a comprehensive model for recognizing, measuring, presenting and disclosing in the financial statements uncertain tax positions taken or expected to be taken. The Partnership is a pass-thru entity and does not expect a major impact on the financial statements as a result of FIN 48.

On September 13, 2006, the Securities Exchange Commission (SEC) issued Staff Accounting Bulleting No. 108 (SAB 108), which establishes an approach that requires quantification of financial statement errors based on the effects of the error on each of the company's financial statements and the related disclosures. SAB 108 requires the use of a balance sheet and an income statement approach to evaluate whether either of these approaches results in quantifying a misstatement that, when all relevant quantitative and qualitative factors are considered, is material. SAB 108 is not expected to have a material impact on the Partnership.

(3) Significant Asset Purchases and Acquisitions

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 referred to as 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.

In November 2005, the Partnership acquired El Paso Corporation's processing and natural gas liquids business in south Louisiana for $481.0 million. The assets acquired include 2.3 billion cubic feet per day of processing capacity, 66,000 barrels per day of fractionation capacity, 2.4 million barrels of underground storage and 400 miles of liquids transport lines. The Partnership financed the acquisition with net proceeds totaling $228.0 million from the issuance of common units and senior subordinated series B units (including the 2% general partner contributions totaling $4.7 million) and borrowings under its bank credit facility for the remaining balance.

We have utilized the purchase method of accounting for this acquisition with an acquisition date of November 1, 2005. The purchase price and our allocation thereof are as follows (in thousands):

Cash paid to El Paso Corporation (net of estimated working capital adjustment)	$	477,851
Direct acquisition costs		3,125
Total Purchase Price	$	480,976
Assets acquired:		
Current assets	$	49,693
Property, plant & equipment		235,599
Intangible assets		253,775
Liabilities assumed:		
Current liabilities		(58,091)
Total Purchase Price	$	480,976

Intangible assets relate to customer relationships and are being amortized over 15 years. In 2006, the purchase price for El Paso was increased $3.1 million due to changes in assets and liabilities assumed with the purchase.

On June 29, 2006, the Partnership acquired certain natural gas gathering pipeline systems and related facilities in the Barnett Shale (North Texas Gathering (NTG) assets) from Chief Holdings LLC (Chief) for a purchase price of approximately $475.3 million (the Chief Acquisition). The NTG assets include five gathering systems, located in parts of Parker, Tarrant, Denton, Palo Pinto, Erath, Hood, Somervell, Hill and Johnson counties in Texas. The NTG assets also included a 125 million cubic feet per day carbon dioxide treating plant and compression facilities with 26,000 horsepower. The gas gathering systems consisted of approximately 250 miles of existing gathering pipelines, ranging from four inches to twelve inches in diameter. The Partnership plans to build up to an additional

400 miles of pipelines as production in the area is drilled and developed. The gathering systems had the capacity to deliver approximately 250,000 MMBtu per day at the date of acquisition.

Simultaneously with the Chief Acquisition, the Partnership entered into a gas gathering agreement with Devon Energy Corporation (Devon) whereby the Partnership has agreed to gather, and Devon has agreed to dedicate and deliver, the future production on acreage that Devon acquired from Chief (approximately 160,000 net acres). Under the agreement, Devon has committed to deliver all of the production from the dedicated acreage into the gathering system, including production from current wells and wells that it drills in the future. The Partnership will expand the gathering system to reach the new wells as they are drilled. The agreement has a 15-year term and provides for market-based gathering fees over the term. In addition to the Devon agreement, approximately 60,000 additional net acres are dedicated to the Midstream Assets under agreements with other producers.

The Partnership utilized the purchase method of accounting for the acquisition of the Midstream Assets with an acquisition date of June 29, 2006. The Partnership will recognize the gathering fee income received from Devon and other producers who deliver gas into the Midstream Assets as revenue at the time the natural gas is delivered. The purchase price and our preliminary allocation thereof are as follows (in thousands):

Cash paid to Chief	$	474,858
Direct acquisition costs		429
Total purchase price	$	475,287
Assets acquired:		
Current assets	$	18,833
Property, plant and equipment		115,728
Intangible assets		395,604
Liabilities assumed:		
Current liabilities		(54,878)
Total purchase price	$	475,287

Intangibles relate primarily to the value of the dedicated and non-dedicated acreage attributable to the system, including the agreement with Devon, and are being amortized using the units of throughput method of amortization. The preliminary purchase price allocation has not been finalized because the Partnership is still in the process of determining the allocation of costs between tangible and intangible assets and finalizing working capital settlements.

The Partnership financed the Chief Acquisition with borrowings of approximately $105.0 million under its bank credit facility, net proceeds of approximately $368.3 million from the private placement of senior subordinated series C units, including approximately $9.0 million of equity contributions from Crosstex Energy GP, L.P., the general partner of the Partnership and an indirect subsidiary of CEI, and $6.0 million of cash.

Operating results for the El Paso assets have been included in the consolidated statements of operations since November 1, 2005. Operating results for the Midstream assets have been included in the consolidated statements of operations since June 29, 2006. The following unaudited pro forma results of operations assume that the El Paso and Midstream Asset acquisitions occurred on January 1, 2005 (in thousands, except per unit amounts):

	Pro Forma (Unaudited) Years Ended December 31,	
	2006	2005
Revenue	$ 3,155,854	$ 3,320,474
Net income and (loss)	$ (8,808)	$ 5,766
Net income (loss) per limited partner unit		
Basic	$ (0.96)	$ (0.20)
Diluted	$ (0.96)	$ (0.19)
Weighted average limited partners' units outstanding		
Basic	26,337	24,713
Diluted	26,337	26,234

There are substantial differences in the way Chief operated the Midstream Assets during pre-acquisition periods and the way the Partnership operates these assets post-acquisition. The historical operating results for the El Paso assets only reflect direct revenues and expenses for such assets and did not include any general and administrative expenses because such expenses were not separately allocated to the acquired companies. Although the unaudited pro forma results of operations include adjustments to reflect the significant effects of the acquisitions, these pro forma results do not purport to present the results of operations had the acquisitions actually been completed as of January 1, 2005.

(4) Investment in Limited Partnerships and Note Receivable

The Partnership owns a 50% interest in CDC and consolidates its investment in CDC pursuant to FIN No. 46R. The Partnership manages the business affairs of CDC. The other 50% joint venture partner (the CDC partner) is an unrelated third party who owns and operates a natural gas field located in Denton County.

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 balance remaining on the note of $0.9 million is included in current notes receivable as of December 31, 2006.

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., or 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 year ended December 31, 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.

(5) Long-Term Debt

As of December 31, 2006 and 2005, long-term debt consisted of the following (in thousands):

	2006	2005
Bank credit facility, interest based on Prime or LIBOR plus an applicable margin, interest rates at December 31, 2006 and 2005 were 7.20% and 6.69%, respectively	$ 488,000	$ 322,000
Senior secured notes, weighted average interest rates at December 31, 2006 and 2005 of 6.76% and 6.64%, respectively	498,530	200,000
Note payable to Florida Gas Transmission Company	600	650
	987,130	522,650
Less current portion	(10,012)	(6,521)
Debt classified as long-term	$ 977,118	$ 516,129

Credit Facility. On June 29, 2006, the Partnership amended its bank credit facility, increasing availability under the facility to $1.0 billion and extending the maturity date from November 2010 to June 2011. The bank credit agreement includes procedures for additional financial institutions selected by the Partnership to become lenders under the agreement, or for any existing lender to increase its commitment in an amount approved by the Partnership and the lender, subject to a maximum of $300 million for all such increases in commitments of new or existing lenders.

The facility was used for the 2005 El Paso acquisition and the 2006 Chief, Hanover and Cardinal acquisitions and will be used to finance the acquisition and development of gas gathering, treating, and processing facilities, as well as working capital, letters of credit, distributions and other general partnership purposes. At December 31, 2006, $564.3 million was outstanding under the facility, including $76.3 million of letters of credit, leaving approximately $435.7 million available for future borrowings. The facility will mature in June 2011, at which time it will terminate and all outstanding amounts shall be due and payable. Amounts borrowed and repaid under the credit facility may be re-borrowed.

Obligations under the bank credit facility are secured by first priority liens on all of the Partnership's material pipeline, gas gathering and processing assets, all material working capital assets and a pledge of all of the Partnership's equity interests in certain of its subsidiaries, and rank *pari passu* in right of payment with the senior secured notes. The bank credit facility is guaranteed by certain of the Partnership's subsidiaries. The Partnership 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.

Under the amended credit agreement, borrowings bear interest at the Partnership's option at the administrative agent's reference rate plus 0% to 0.25% or LIBOR plus 1.00% to 1.75%. The applicable margin varies quarterly based on the Partnership's leverage ratio. The fees charged for letters of credit range from 1.00% to 1.75% per annum, plus a fronting fee of 0.125% per annum. The Partnership will incur quarterly commitment fees ranging from 0.20% to 0.375% on the unused amount of the credit facilities.

The credit agreement prohibits the Partnership 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 or its operating partnership's partnership agreement; and
- engage in transactions with affiliates.

The bank credit facility contains the following covenants requiring the Partnership to maintain:

- an initial ratio of total funded debt to consolidated earnings before interest, taxes, depreciation and amortization (each as defined in the credit agreement), measured quarterly on a rolling four-quarter basis, of 5.25 to 1.00, pro forma for any asset acquisitions. The maximum leverage ratio is reduced to 4.75 to 1.00 beginning July 1, 2007 and further reduces to 4.25 to 1.00 on January 1, 2008. The maximum ratio is increased to 5.25 to 1.00 during an acquisition period, as defined in the credit agreement; and
- a minimum interest coverage ratio (as defined in the credit agreement), measured quarterly on a rolling four-quarter basis, equal to 3.0 to 1.0.

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 the Partnership or any of its subsidiaries, in excess of certain allowances;
- certain ERISA events involving the Partnership or the Partnership's 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.

In November 2006, we entered into an interest rate swap covering a principal amount of $50.0 million under the credit facility for a period of three years. We are subject to interest rate risk on our credit facility. The interest rate swap reduces this risk by fixing the LIBOR rate, prior to credit margin, at 4.95%, on $50.0 million of related debt outstanding over the term of the swap agreement which expires on November 30, 2009. We have elected not to designate this swap as a cash flow hedge for FAS 133 accounting treatment. Accordingly, unrealized gains or losses relating to the swap flow through the Consolidated Statement of Operations as adjustments to interest expense over the period hedged. The fair value of the interest rate swap at December 31, 2006 was a $0.1 million asset.

Senior Secured Notes. The Partnership entered into a master shelf agreement with an institutional lender in 2003 that was amended in subsequent years to increase availability under the agreement, pursuant to which it issued the following senior secured notes (dollars in thousands):

Month Issued	Amount	Interest Rate	Maturity	Principal Payment Terms
June 2003	$ 30,000	6.95%	7 years	Quarterly payments of $1,765 from June 2006-June 2010
July 2003	10,000	6.88%	7 years	Quarterly payments of $588 from July 2006-July 2010
June 2004	75,000	6.96%	10 years	Annual payments of $15,000 from July 2010-July 2014
November 2005	85,000	6.23%	10 years	Annual payments of $17,000 from November 2010-December 2014
March 2006	60,000	6.32%	10 years	Annual payments of $12,000 from March 2012-March 2016
July 2006	245,000	6.96%	10 years	Annual payments of $49,000 from July 2012-July 2016
Total Issued	505,000			
Principal repaid	(6,470)			
Balance as of December 31, 2006	$ 498,530			

The availability under the amended shelf agreement governing the senior secured notes is $510.0 million at December 31, 2006.

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 $40.0 million of senior secured notes issued in 2003 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 senior secured notes issued 2004, 2005 and 2006 provide for a call premium of 103.5% of par beginning three years after issuance at rates declining from 103.5% to 100.0%. The notes are not callable prior to three years after issuance. During 2007 the notes may also incur an additional fee each quarter ranging from 0.08% to 0.15% per annum on the outstanding borrowings if the Partnership's leverage ratio, as defined in the agreement, exceeds certain levels, during such quarterly period.

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, 2006 and 2005 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, the lenders under the bank credit facility and the purchasers of the senior secured notes have entered into an Intercreditor and Collateral Agency Agreement, which has been acknowledged and agreed to by the Partnership and its subsidiaries. This agreement appointed Bank of America, N.A. to act as collateral agent and authorized Bank of America to execute various security documents on behalf of the lenders under the bank credit facility and the 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 $0.8 million to FGTC that is payable in $0.1 million annual increments through June 2006 with a final payment of $0.6 million 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, 2006 are as follows (in thousands):

2007	$ 10,012
2008	9,412
2009	9,412
2010	20,294
2011	520,000
Thereafter	418,000

(6) Partners' Capital

(a) Issuance of Common Units, Senior Subordinated Units, Senior Subordinated Series B Units and Senior Subordinated Series C Units

On June 24, 2005, the Partnership issued 1,495,410 senior subordinated units in a private equity offering for net proceeds of $51.1 million, including Crosstex Energy GP, L.P.'s general partner capital contribution of $1.1 million. The senior subordinated units were issued at $33.44 per unit, which represented a discount of 13.7% to the market value of common units on such date, and automatically converted to common units on a one-for-one basis on February 24, 2006. The senior subordinated units received no distributions until their conversion to common units.

On November 1, 2005, the Partnership issued 2,850,165 senior subordinated series B units in a private placement for a purchase price of $36.84 per unit. The Partnership received net proceeds of approximately $107.1 million, including Crosstex Energy GP, L.P.'s general partner capital contribution of $2.1 million and expenses associated with the sale. The senior subordinated series B units automatically converted into common units on November 14, 2005 at a ratio of one common unit for each senior subordinated series B unit. The senior subordinated series B units were not entitled to distributions paid on November 14, 2005. The net proceeds were used to fund a portion of the El Paso acquisition.

In November and December 2005, the Partnership issued 3,731,050 additional common units to the public at a purchase price of $33.25 per unit. The offering resulted in net proceeds to the Partnership of approximately $120.9 million including Crosstex Energy GP, L.P.'s general partner capital contribution of $2.5 million and net of expenses associated with the offering. The net proceeds from this offering were used to fund a portion of the El Paso acquisition.

On June 29, 2006, the Partnership issued an aggregate of 12,829,650 senior subordinated series C units representing limited partner interests of the Partnership in a private equity offering for net proceeds of approximately $359.3 million. The senior subordinated series C units were issued at $28.06 per unit, which represented a discount of 25% to the market value of common units on such date. CEI purchased 6,414,830 of the senior subordinated series C units. In addition, Crosstex Energy GP, L.P. made a general partner contribution of $9.0 million in connection with this issuance to maintain its 2% general partner interest.

The senior subordinated series C units will automatically convert into common units representing limited partner interests of the Partnership on the first date on or after February 16, 2008 that conversion is permitted by its partnership agreement at a ratio of one common unit for each senior subordinated series C unit. The Partnership's partnership agreement will permit the conversion of the senior subordinated series C units to common units once the subordination period ends or if the issuance is in connection with an acquisition that increases cash flow from operations per unit on a pro forma basis. If not able to convert on February 16, 2008, then the holders of such units will have the right to receive, after payment of the minimum quarterly distribution on the Partnership's common units but prior to any payment on the Partnership's subordinated units, distributions equal to 110% of the quarterly cash distribution amount payable on common units. The senior subordinated series C units are not entitled to distributions of available cash from the Partnership until February 16, 2008.

(b) 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.

(c) 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 except as discussed in (d) below. 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.

(d) Early Conversion of Subordinated Units

If the Partnership meets the applicable financial tests in the partnership agreement for the three consecutive four-quarter periods ending on December 31, 2005 or December 31, 2006, up to 4,666,000 of the subordinated units may be converted into common units prior to December 31, 2007. The Partnership met the financial tests for three consecutive four-quarter periods ended December 31, 2005, so 2,333,000 subordinated units converted to common units upon the payment of the fourth quarter distribution on February 15, 2006. The Partnership also met these tests for the three consecutive four-quarter periods ended December 31, 2006, so an additional 2,333,000 of the subordinated units converted to common units upon the payment of the fourth quarter distribution on February 15, 2007.

(e) 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 $20.4 million, $10.8 million and $5.6 million were earned by our general partner for the years ended December 31, 2006, 2005 and 2004, 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 $2.18, $1.93 and $1.70 for the years ended December 31, 2006, 2005 and 2004, respectively.

The Partnership increased its fourth quarter distribution on its common and subordinated units to $0.56 per unit which was paid on February 15, 2007.

(7) Retirement Plans

The Partnership sponsors a single employer 401(k) plan for employees who become eligible upon the date of hire. The plan allows for contributions to be made at each compensation calculation period based on the annual discretionary contribution rate. Contributions of $1.1 million, $0.6 million and $0.5 million were made to the plan for the years ended December 31, 2006, 2005, and 2004, respectively.

(8) Employee Incentive Plans

(a) Long-Term Incentive Plan

In December 2002, the Partnership's managing general partner adopted a long-term incentive plan for its employees, directors, and affiliates who perform services for the Partnership. The plan currently permits the grant of awards covering an aggregate of 2,600,000 common unit options and restricted units. The plan is administered by the compensation committee of the managing general partner's board of directors. The units issued upon exercise or vesting are newly issued units.

(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 its general partner's 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. The restricted units include a tandem award that entitles the participant to receive cash payments equal to the cash distributions made by the Partnership with respect to its outstanding common units until the restriction period is terminated or the restricted units are forfeited. The restricted units granted prior to 2005 generally vest based on five years of service (25% in years 3 and 4 and 50% in year 5) and the restricted units granted in 2005 and 2006 generally cliff vest after three years of service.

The restricted units are valued at their fair value at the date of grant which is equal to the market value of common units on such date. A summary of the restricted unit activity for the year ended December 31, 2006 is provided below:

Crosstex Energy, L.P. Restricted Units:	Number of Units	Weighted Average Grant-Date Fair Value
Non-vested, beginning of period	247,648	$ 28.33
Granted	130,008	35.01
Vested	(19,500)	12.99
Forfeited	(21,652)	25.69
Non-vested, end of period	336,504	$ 31.97
Aggregate intrinsic value, end of period (in thousands)	$ 13,410	

Restricted units totaling 163,934 were granted in 2005 with a weighted average grant-date fair value of $36.66 per unit. No restricted units were granted in 2004.

The aggregate intrinsic value of vested units during the year ended December 31, 2006 was $0.7 million. As of December 31, 2006, there was $5.8 million of unrecognized compensation cost related to non-vested restricted units. That cost is expected to be recognized over a weighted-average period of 1.8 years. The Partnership recognized stock-based compensation expense of $1.2 million and $0.3 million related to the amortization of restricted units in 2005 and 2004, respectively, in accordance with APB No. 25.

(c) Unit Options

Unit options will have an exercise price that is not less 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, its general partner or its general partner's general partner.

The fair value of each unit option award is estimated at the date of grant using the Black-Scholes-Merton model. This model is based on the assumptions summarized below. Expected volatilities are based on historical volatilities of the Partnership's traded common units. The Partnership has used historical data to estimate share option exercise and employee departure behavior. The expected life of unit options represents the period of time that unit options granted are expected to be outstanding. The risk-free interest rate for periods within the contractual term of the unit option is based on the U.S. Treasury yield curve in effect at the time of the grant.

Unit options are generally awarded with an exercise price equal to the market price of the Partnership's common units at the date of grant, although a substantial portion of the unit options granted during 2004 and 2005 were granted during the second quarter of each fiscal year with an exercise price equal to the market price at the beginning of the fiscal year, resulting in an exercise price that was less than the market price at grant. In accordance with APB No. 25, compensation expense was recorded during 2004 and 2005 to the extent the market value of the unit exceeded the exercise price of the unit option at the measurement date. The unit options granted prior to 2005 generally vest based on five years of service (25% in years 3 and 4 and 50% in year 5) and the unit options granted in 2005 and 2006 generally vest based on 3 years of service (one-third after each year of service). The following weighted average assumptions were used for the Black-Scholes option-pricing model for grants in 2006, 2005 and 2004:

	Years Ended December 31,		
Crosstex Energy, L.P. Unit Options Granted:	**2006**	**2005**	**2004**
Weighted average distribution yield	5.5%	5.5%	6.4%
Weighted average expected volatility	33.0%	33.0%	29.0%
Weighted average risk free interest rate	4.80%	3.83%	3.25%
Weighted average expected life	6 years	5.0 years	4.9 years
Weighted average contractual life	10 years	10 years	10 years
Weighted average of fair value of unit options granted	$ 7.45	$ 8.42	$ 4.00

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements — (Continued)

A summary of the unit option activity for the years ended December 31, 2006, 2005 and 2004 is provided below:

	Years Ended December 31,					
	2006		2005		2004	
	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	1,039,832	$ 18.88	1,043,865	$ 15.58	643,272	$ 10.28
Granted	286,403	34.62	193,511	32.78	466,296	22.52
Exercised	(304,936)	11.19	(127,097)	10.57	(39,066)	11.00
Forfeited	(95,143)	24.56	(70,447)	23.15	(26,637)	15.64
Outstanding, end of period	926,156	$ 25.70	1,039,832	$ 18.88	1,043,865	$ 15.58
Options exercisable at end of period	121,131	$ 23.58	308,455	$ 11.34	263,078	$ 10.36
Weighted average contractual term (years) end of period:						
Options outstanding	7.8	—	—	—	—	—
Options exercisable	7.5	—	—	—	—	—
Aggregate intrinsic value end of period (in thousands):						
Options outstanding	$ 13,107	—	—	—	—	—
Options exercisable	$ 1,970	—	—	—	—	—
Weighted average fair value of options granted with an exercise price equal to market price at grant	(a)	(a)	—	—	116,902	$ 4.91
Weighted average fair value of options granted with an exercise price less than market price at grant	(a)	(a)	193,511	$ 8.42	349,394	$ 3.70

(a) Disclosure not required under FAS No. 123R. No options were granted with an exercise price less than market value at grant during 2006.

The total intrinsic value of unit options exercised during the years ended December 31, 2006, 2005 and 2004 was $7.6 million, $3.5 million and $0.5 million, respectively. As of December 31, 2006, there was $2.6 million of unrecognized compensation cost related to non-vested unit options. That cost is expected to be recognized over a weighted-average period of 1.8 years.

(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. Prior to September 6, 2006, the plan permitted the grant of awards covering an aggregate of 1,200,000 options for common stock and restricted shares. On September 6, 2006, CEI's board of directors adopted, subject to stockholder approval, an Amended and Restated Long-Term Incentive Plan that increased the number of shares of common stock authorized for issuance under the plan to 1,530,000 shares. CEI's stockholders approved the plan on October 26, 2006. The plan is administered by the compensation committee of CEI's board of directors. The shares issued upon exercise or vesting are newly issued common shares.

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements — (Continued)

CEI's restricted shares are included at their fair value at the date of grant which is equal to the market value of the common stock on such date. CEI's restricted stock granted prior to 2005 generally vests based on five years of service (25% in years 3 and 4 and 50% in year 5) and restricted stock granted in 2005 and 2006 generally cliff vest after three years of service. A summary of the restricted stock activity for the year ended December 31, 2006 is provided below:

Crosstex Energy, Inc. Restricted Shares:	Number of Shares(a)	Weighted Average Grant-Date Fair Value(a)
Non-vested, beginning of period	589,641	$ 14.46
Granted	186,840	25.05
Vested	—	—
Forfeited	(24,732)	16.39
Non-vested, end of period	751,749	$ 17.03
Aggregate intrinsic value, end of period (in thousands)	$ 23,823	

(a) Adjusted to reflect three-for-one stock split.

Restricted shares in CEI totaling 404,640 were issued to officers and employees of the Partnership in 2005 with a weighted-average grant-date fair value of $16.73 per share. No CEI restricted shares were granted in 2004.

No CEI stock options were granted to any officers or employees of the Partnership during 2005 and 2006. The following assumptions were used for the Black-Scholes option-pricing model for the 30,000 stock options granted to an officer of the Partnership in 2004:

Weighted average distribution yield	5.4%
Weighted average expected volatility	30.0%
Weighted average risk free interest rate	3.26%
Weighted average expected life	4.5 years
Weighted average contractual life	10 years
Weighted average of fair value of unit options granted (post stock split)	$ 1.59

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements — (Continued)

A summary of the stock option activity for the years ended December 31, 2006, 2005 and 2004 is provided below:

	Years Ended December 31,					
	2006		2005		2004	
	Number of Shares	Weighted Average Exercise Price	Number of Shares(a)	Weighted Average Exercise Price(a)	Number of Shares(a)	Weighted Average Exercise Price(a)
Outstanding, beginning of period	159,933	$ 9.53	2,161,152	$ 2.22	2,587,170	$ 1.81
Granted	—	—	68,958	13.85	130,908	8.48
Cancelled	—	—	(27,060)	15.23	(24,000)	1.71
Exercised	(9,933)	12.58	(2,043,117)	1.87	(532,926)	1.78
Forfeited	(30,000)	13.83	—	—	—	—
Outstanding, end of period	120,000	$ 8.21	159,933	$ 9.53	2,161,152	$ 2.22
Options exercisable at end of period	—	—	9,933	$ 12.58	1,986,249	$ 1.85
Weighted average fair value of options granted with an exercise price equal to market price at grant(a)	(b)	(b)	68,958	$ 3.68	120,000	$ 1.50
Weighted average fair value of options granted with an exercise price less than market at grant(a)	(b)	(b)	—	—	10,908	$ 2.53

(a) Adjusted to reflect three-for-one stock split.

(b) Disclosure not required under FAS No. 123R. No options were granted with an exercise price less than market value at grant during 2006.

The following is a summary of the CEI stock options outstanding attributable to officers and employees of the Partnership as of December 31, 2006:

Outstanding stock options (non exercisable) (post stock split)	30,000
Weighted average exercise price (post stock split)	$ 13.33
Aggregate intrinsic value	$ 550,800
Weighted average remaining contractual term	7.9 years

The total intrinsic value of CEI stock options exercised by officers and employees of the Partnership during the years ended December 31, 2005 and 2004 was $27.0 million and $6.2 million, respectively. No stock options were exercised by officers and employees of the Partnership during the year ended December 31, 2006.

As of December 31, 2006, there was $6.7 million of unrecognized compensation costs related to non-vested CEI restricted stock and CEI's stock options. The cost is expected to be recognized over a weighted average period of 1.8 years.

(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, 2006, 2005 and 2004. The computation of diluted earnings per unit further assumes the dilutive effect of unit options, restricted units and senior subordinated units.

The following are the unit amounts used to compute the basic and diluted earnings per limited partner unit for the years ended December 31, 2006, 2005, and 2004 (in thousands, except per-unit amounts):

	Years Ended December 31, 2006	2005	2004
Basic earnings per unit:			
Weighted average limited partner units outstanding	26,337	19,006	18,081
Dilutive earnings per unit:			
Weighted average limited partner units outstanding	26,337	19,006	18,081
Dilutive effect of restricted units	—	162	98
Dilutive effect of senior subordinated units	—	773	—
Dilutive effect of exercise of options outstanding	—	586	454
Dilutive units	26,337	20,527	18,633

All outstanding units were included in the computation of diluted earnings per unit and weighted based on the number of days such units were outstanding during the period presented. All common unit equivalents were antidilutive for the year ended December 31, 2006 because the limited partners were allocated a net loss in the period.

Net income is allocated to the general partner in an amount equal to its incentive distributions as described in Note 6(e). In June 2005, the Partnership amended its partnership agreement to allocate the expenses attributable to CEI stock options and restricted stock all to the general partner to match the related general partner contribution. Therefore, beginning in the second quarter of 2005, the general partner's share of net income is reduced by stock-based compensation expense attributed to CEI stock options and restricted stock. The remaining net income after incentive distributions and CEI-related stock-based compensation is allocated pro rata between the 2% general partner interest, the subordinated units and the common units. The net income allocated to the general partner is as follows (in thousands):

	Years Ended December 31, 2006	2005	2004
Income allocation for incentive distributions	$ 20,422	$ 10,660	$ 5,550
Stock-based compensation attributable to CEI's stock options and restricted shares	(3,545)	(2,223)	—
2% general partner interest in net income (loss)	(421)	215	363
General Partner Share of Net Income	$ 16,456	$ 8,652	$ 5,913

(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).

	2006		2005	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Cash and cash equivalents	$ 824	$ 824	$ 1,405	$ 1,405
Trade accounts receivable and accrued revenues	367,023	367,023	428,869	428,869
Fair value of derivative assets	26,860	26,860	19,838	19,838
Note receivable	926	926	1,276	1,276
Accounts payable, drafts payable and accrued gas purchases	404,863	404,863	406,880	406,880
Current portion of long-term debt	10,012	10,012	6,521	6,521
Long-term debt	977,118	981,914	516,129	520,005
Fair value of derivative liabilities	14,699	14,699	18,359	18,359

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 $488.0 million and $322.0 million as of December 31, 2006 and 2005, 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, 2006, the Partnership also had borrowings totaling $498.5 million under senior secured notes with a weighted average interest rate of 6.76%. The fair value of these borrowings as of December 31, 2006 and 2005 were adjusted to reflect to current market interest rate for such borrowings as of December 31, 2006 and 2005, respectively.

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 Partnership commonly enters into various derivative financial transactions which it does not designate as hedges. These transactions include "swing swaps", "third party on-system financial swaps", "marketing financial swaps", "storage swaps" and "basis swaps". Swing swaps are generally short-term in nature (one month), and are usually entered into to protect against changes in the volume of daily versus first-of-month index priced gas supplies or markets. Third party on-system financial swaps are hedges that the Partnership enters into on behalf of its customers who are connected to its systems, wherein the Partnership fixes a supply or market price for a period of time for its customers, and simultaneously enters into the derivative transaction. Marketing financial swaps are similar to on-system financial swaps, but are entered into for customers not connected to the Partnership's systems. Storage swaps transactions protect against changes in the value of gas that the Partnership has stored to serve various operational requirements. Basis swaps are used to hedge basis location price risk due to buying gas into one of the Partnership's systems on one index and selling gas off that same system on a different index.

In August 2005 the Partnership acquired puts, or rights to sell a portion of the liquids from the plants at a fixed price over a two-year period beginning January 1, 2006 for a premium of $18.7 million as part of the overall risk management plan related to the acquisition of the El Paso assets which closed on November 1, 2005. In December 2005 the Partnership sold a portion of those puts for $4.3 million. The Partnership did not designate these put options to obtain hedge accounting and therefore, these put options were marked to market through our consolidated statement of operations for the years ended December 31, 2005 and 2006. The puts represent options, but not obligations, to sell the related underlying liquids volumes at a fixed price.

The components of (gain) loss on derivatives in the Consolidated Statements of Operations are (in thousands):

	December 31, 2006	December 31, 2005	December 31, 2004
Change in fair value of derivates that do not qualify for hedge accounting	$ 713	$ 10,169	$ 769
Realized (gains) losses on derivatives	(2,238)	(240)	(1,031)
Ineffective portion of derivatives qualifying for hedge accounting	(74)	39	(17)
	$ (1,599)	$ 9,968	$ (279)

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

	December 31, 2006	December 31, 2005
Fair value of derivative assets — current	$ 22,959	$ 12,205
Fair value of derivative assets — long term	3,812	7,633
Fair value of derivative liabilities — current	(12,141)	(14,782)
Fair value of derivative liabilities — long term	(2,558)	(3,577)
Net fair value of derivatives	$ 12,072	$ 1,479

Set forth below is the summarized notional amount and terms of all instruments held for price risk management purposes at December 31, 2006 (all quantities are expressed in British Thermal Units and liquids are expressed in gallons). The remaining term of the contracts extend no later than March 2008 for derivatives, excluding third-party on-system financial swaps, and extend to June 2010 for third-party on-system financial swaps. The Partnership's counterparties to derivative contracts include BP Corporation, Total Gas & Power, Fortis, UBS Energy, Morgan Stanley and J. Aron & Co., a subsidiary of Goldman Sachs. 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.

December 31, 2006				
Transaction Type	Total Volume	Pricing Terms	Remaining Term of Contracts	Fair Value (In thousands)
Cash Flow Hedges:				
Natural gas swaps	171,000	NYMEX less a basis of $0.785 to NYMEX less a basis of $0.575 or fixed prices ranging from $8.20 to $10.855 settling against various Inside FERC Index prices	January 2007 — June 2007	$ 73
Natural gas swaps	(3,117,000)		January 2007 — March 2008	6,191
Total natural gas swaps designated as cash flow hedges				$ 6,264

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements — (Continued)

	December 31, 2006			
Transaction Type	Total Volume	Pricing Terms	Remaining Term of Contracts	Fair Value (In thousands)
Liquids swaps	(26,747,768)	Fixed prices ranging from $0.61 to $1.6275 settling against Mt. Belvieu Average of daily postings (non-TET)	January 2007 — March 2008	$ 1,766
Total liquids swaps designated as cash flow hedges				$ 1,766
Mark to Market Derivatives:				
Swing swaps	1,685,625	Prices ranging from Inside FERC Index less $0.0275 to Inside FERC Index plus $0.01 or a fixed price of $5.93 settling against various Gas Daily Index prices	January 2007	$ (2)
Swing swaps	(651,000)		January 2007	(12)
Total swing swaps				$ (14)
Physical offset to swing swap transactions	651,000	Prices of various Inside FERC Index prices settling against various Gas Daily Index prices	January 2007	—
Physical offset to swing swap transactions	(1,685,625)		January 2007	—
Total physical offset to swing swaps				$ —
Basis swaps	31,040,000	NYMEX less a basis of $0.785 to NYMEX plus a basis of $0.145 or prices ranging from $7.31 to $10.505 settling against various Inside FERC Index prices.	January 2007 — March 2008	$ (31)
Basis swaps	(31,414,000)		January 2007 — March 2008	(137)
Total basis swaps				$ (168)
Physical offset to basis swap transactions	5,090,000	Prices ranging from Inside FERC Index less $0.09 to Inside FERC Index plus $0.0175 or a fixed price of $7.31 settling against various Inside FERC Index prices	January 2007 — March 2007	$ (30,417)
Physical offset to basis swap transactions	(4,935,000)		January 2007 — March 2007	30,891
Total physical offset to basis swap transactions				$ 474

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements — (Continued)

Transaction Type	Total Volume	Pricing Terms	Remaining Term of Contracts		Fair Value (In thousands)
		December 31, 2006			
Third party on-system financial swaps	8,415,800	Fixed prices ranging from $5.659 to $11.91 settling against various Inside FERC Index prices	January 2007 — June 2010	$	(9,420)
Total third party on-system financial swaps				$	(9,420)
Physical offset to third party on-system transactions	(8,415,800)	Fixed prices ranging from $5.71 to $11.96 settling against various Inside FERC Index prices	January 2007 — June 2010	$	10,176
Total physical offset to third party on-system swaps				$	10,176
Storage swap transactions:					
Storage swap transactions	(355,000)	Fixed price of $10.065 settling against Inside FERC Henry Hub Index price	February 2007	$	1,333
Total financial storage swap transactions				$	1,333
Natural gas liquid puts:					
Liquid put options (purchased)	80,497,830	Fixed prices ranging from $0.565 to $1.26 settling against Mount Belvieu Average Daily Index	January 2007 — December 2007	$	3,117
Liquid put options (sold)	(37,713,696)		January 2007 — December 2007		(1,456)
Total natural gas liquid puts				$	1,661

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.

Impact of Cash Flow Hedges

Natural Gas

For the year ended December 31, 2006, net gains on futures and basis swap hedge contracts increased gas revenue by $5.9 million. For the year ended December 31, 2005, net losses on futures and basis swap hedge contracts decreased gas revenue by $7.0 million. As of December 31, 2006, an unrealized pre-tax derivative fair value gain of $6.3 million, related to cash flow hedges of gas price risk, was recorded in accumulated other comprehensive income. Of this amount, $5.4 million is expected to be reclassified into earnings through December 2007. The actual reclassification to earnings will be based on mark-to-market prices at the contract settlement date, along with the realization of the gain or loss on the related physical volume, which amount is not reflected above.

The settlement of futures contracts and basis swap agreements related to January 2007 gas production increased gas revenue by approximately $0.7 million.

Liquids

For the year ended December 31, 2006, net gains on liquids swap hedge contracts increased liquids revenue by approximately $1.5 million. For the year ended December 31, 2005, net losses on liquids swap hedge contracts decreased liquids revenue by approximately $1.2 million. For the year ended December 31, 2006, an unrealized pre-tax derivative fair value gain of $1.8 million related to cash flow hedges of liquids price risk was recorded in accumulated other comprehensive income. Of this amount, $1.5 million is expected to be reclassified into earnings through December 2007. The actual reclassification to earnings will be based on mark-to-market prices at the contract settlement date, along with the realization of the gain or loss on the related physical volume, which amount is not reflected above.

Assets and liabilities related to third party derivative contracts, swing swaps, storage swaps and puts are included in the fair value of derivative assets and liabilities and the profit and loss on the mark to market value of these contracts are recorded on a net basis as gain (loss) on derivatives in the consolidated statement of operations. The Partnership estimates the fair value of all of its energy trading contracts using actively quoted prices. 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	More Than Two Years	Total Fair Value
December 31, 2006	$ 3,872	$ 49	$ 121	$ 4,042

(11) Transactions with Related Parties

The Partnership treats gas for and purchases gas from, Camden Resources, Inc. (Camden) and treats gas for Erskine Energy Corporation (Erskine) and Approach Resources, Inc. (Approach). All three entities are affiliates of the Partnership by way of equity investments made by Yorktown, a major shareholder in CEI. During the years ended December 31, 2006, 2005 and 2004, the Partnership purchased natural gas from Camden in the amount of approximately $32.5 million, $67.2 million, and $38.4 million, respectively, and received approximately $2.6 million, $2.6 million, and $2.4 million, respectively, in treating fees from Camden. During the year ended December 31, 2006, the Partnership received treating fees of $1.3 million and $0.3 million from Erskine and Approach, respectively.

During the year 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 year ended December 31, 2004, the Partnership bought natural gas from CPP in the amount of approximately $11.6 million and paid approximately $51,000 to CPP for transportation.
- During the year ended December 31, 2004, the Partnership received a management fee from CPP in the amount of approximately $125,000.
- During the year ended December 31, 2004, the Partnership received distributions from CPP in the amount of approximately $159,000.

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.

CEI paid the Partnership $0.5 million, $0.3 million and $0.4 million during the years ended December 31, 2006, 2005 and 2004, respectively, to cover its portion of administrative and compensation costs for offices and employees that perform services for CEI.

(12) Commitments and Contingencies

(a) Leases — Lessee

We have operating leases for office space, office and field equipment and the Eunice plant. The Eunice plant operating lease acquired in the El Paso acquisition provides for annual lease payments of $12.2 million with a lease term extending to November 2012. At the end of the lease term we have the option to purchase the plant for $66.3 million or to renew the lease for up to an additional 9.5 years at 50% of the lease payments under the current lease.

The following table summarizes our remaining non-cancelable future payments under operating leases with initial or remaining non-cancelable lease terms in excess of one year (in millions):

2007	$ 18.7
2008	17.8
2009	17.1
2010	16.0
2011	16.0
Thereafter	17.6
	$ 103.2

Operating lease rental expense in the years ended December 31, 2006, 2005 and 2004, was approximately $23.8 million, $3.4 million, and $2.8 million, respectively.

(b) Leases — Lessor

During 2006, the Partnership leased approximately 54 of its treating plants and 33 of its dew point control 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 cancelable leases. As of December 31, 2006, the Partnership only had 29 treating plants under operating leases with remaining non-cancelable lease terms in excess of one year. The future minimum lease rentals are $10.6 million and $6.7 million for the years ended December 31, 2007 and 2008, respectively. These leased treating plants have a cost of $35.0 million and accumulated depreciation of $6.6 million as of December 31, 2006.

(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 the South Louisiana Processing Assets from the El Paso Corporation in November 2005. One of the acquired locations, the Cow Island Gas Processing Facility, has a known active remediation project for benzene contaminated groundwater. The cause of contamination was attributed to a leaking natural gas condensate storage tank. The site investigation and active remediation being conducted at this location is under the guidance of the Louisiana Department of Environmental Quality (LDEQ) based on the Risk-Evaluation and Corrective Action Plan Program (RECAP) rules. In addition, the Partnership is working with both the LDEQ and the Louisiana State University, Louisiana Water Resources Research Institute, on the development and implementation of a new remediation technology that will drastically reduce the remediation time as well as the costs associated with such remediation projects. The estimated remediation costs are expected to be approximately

$0.5 million. Since this remediation project is a result of previous owners' operation and the actual contamination occurred prior to the Partnership's ownership, these costs were accrued as part of the purchase price.

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.

The Partnership acquired assets from Duke Energy Field Services, or DEFS, in June 2003 that have environmental contamination, including a gas plant in Montgomery County near Conroe, Texas. At Conroe, contamination from historical operations has been identified at levels that exceed the applicable state action levels. Consequently, site investigation and/or remediation are underway to address those impacts. The estimated remediation cost for the Conroe plant site is currently estimated to be approximately $3.2 million. Under the purchase agreement, DEFS has retained liability for cleanup of the Conroe site. Moreover, a third-party company has assumed the remediation costs associated with the Conroe site. Therefore, the Partnership does not expect to incur any material environmental liability associated with the Conroe site.

(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.

(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 south Louisiana processing and liquids assets, the processing and transmission assets located in north and south Texas, the LIG pipelines and processing plants located in Louisiana, the Mississippi System, the Arkoma system in Oklahoma and various other small systems. Also included in the Midstream division are the Partnership's energy trading 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. The Seminole carbon dioxide processing plant located in Gaines County, Texas is included in the Treating division.

The accounting policies 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 operating revenues and segment profits. Corporate expenses include general partnership expenses associated with managing all reportable operating segments. Corporate assets consist principally of property and equipment, including software, for general corporate support, working capital and debt financing costs.

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	Corporate	Totals
		(In thousands)		
Year ended December 31, 2006:				
Sales to external customers	$ 3,073,069	$ 66,225	$ —	$ 3,139,294
Profit on energy trading activities	2,510	—	—	2,510
Purchased gas	(2,859,815)	(9,463)	—	(2,869,278)
Operating expenses	(80,943)	(20,048)	—	(100,991)
Segment profit	$ 134,821	$ 36,714	$ —	$ 171,535
Inter-segment sales	$ 10,520	$ (10,520)	$ —	$ —
Gain (loss) on derivatives	$ 1,591	$ 8	$ —	$ 1,599
Depreciation and amortization	$ (63,348)	$ (15,800)	$ (3,583)	$ (82,731)
Capital expenditures (excluding acquisitions)	$ 294,597	$ 31,463	$ 8,184	$ 334,244
Identifiable assets	$ 1,960,213	$ 203,528	$ 30,733	$ 2,194,474
Year ended December 31, 2005:				
Sales to external customers	$ 2,982,874	$ 48,606	$ —	$ 3,031,480
Profit on energy trading activities	1,568	—	—	1,568
Purchased gas	(2,860,823)	(9,706)	—	(2,870,529)
Operating expenses	(41,965)	(14,771)	—	(56,736)
Segment profit	$ 81,654	$ 24,129	$ —	$ 105,783
Inter-segment sales	$ 10,003	$ (10,003)	$ —	$ —
Gain (loss) on derivatives(a)	$ (9,968)	$ —	$ —	$ (9,968)
Depreciation and amortization	$ (23,243)	$ (10,646)	$ (2,135)	$ (36,024)
Capital expenditures (excluding acquisitions)	$ 98,284	$ 22,886	$ 6,512	$ 127,682
Identifiable assets	$ 1,278,017	$ 130,435	$ 16,706	$ 1,425,158
Year ended December 31, 2004:				
Sales to external customers	$ 1,948,021	$ 30,755	$ —	$ 1,978,776
Profit on energy trading activities	2,228	—	—	2,228
Purchased gas	(1,861,204)	(5,274)	—	(1,866,478)
Operating expenses	(29,484)	(8,856)	—	(38,340)
Segment profit	$ 59,561	$ 16,625	$ —	$ 76,186
Inter-segment sales	$ 6,360	$ (6,360)	$ —	$ —
Gain (loss) on derivatives	$ 279	$ —	$ —	$ 279
Depreciation and amortization	$ (15,106)	$ (7,272)	$ (656)	$ (23,034)
Capital expenditures (excluding acquisitions)	$ 17,405	$ 25,141	$ 3,438	$ 45,984
Identifiable assets	$ 487,748	$ 90,287	$ 8,736	$ 586,771

(a) Midstream segment profit is net of non-cash derivative loss of $10.2 million.

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements — (Continued)

The following table reconciles the segment profits reported above to the operating income as reported in the consolidated statements of operations (in thousands):

	Years Ended December 31, 2006	2005	2004
Segment profits	$ 171,535	$ 105,783	$ 76,186
General and administrative expenses	(45,694)	(32,697)	(20,866)
Gain (loss) on derivatives	1,599	(9,968)	279
Gain (loss) on sale of property	2,108	8,138	12
Depreciation and amortization	(82,731)	(36,024)	(23,034)
Operating income	$ 46,817	$ 35,232	$ 32,577

(14) Quarterly Financial Data (Unaudited)

Summarized unaudited quarterly financial data is presented below.

	First	Second	Third	Fourth	Total
	(In thousands, except per unit data)				
2006					
Revenues	$ 817,119	$ 744,655	$ 855,285	$ 724,745	$ 3,141,804
Operating income	9,975	9,997	16,271	10,574	46,817
Net income (loss)	2,040	(2,259)	903	(4,875)	(4,191)
Earnings (loss) per limited partner unit-basic	$ (0.08)	$ (0.23)	$ (0.12)	$ (0.34)	$ (0.78)
Earnings (loss) per limited partner unit-diluted	$ (0.08)	$ (0.23)	$ (0.12)	$ (0.34)	$ (0.78)
2005					
Revenues	$ 549,989	$ 630,805	$ 782,757	$ 1,069,497	$ 3,033,048
Operating income	6,710	7,500	3,976	17,046	35,232
Net income	3,180	4,484	1,072	10,464	19,200
Earnings per limited partner unit — basic	$ 0.06	$ 0.18	$ (0.05)	$ 0.33	$ 0.56
Earnings per limited partner unit — diluted	$ 0.06	$ 0.17	$ (0.05)	$ 0.30	$ 0.51

Schedule II

CROSSTEX ENERGY, L.P.
(In thousands)

	Balance at Beginning of Period	Charged to Costs and Expenses	Deductions	Balance at End of Period
		(In thousands)		
Year ended December 31, 2006 Allowance for doubtful accounts	$ 259	$ 359	—	$ 618
Year ended December 31, 2005 Allowance for doubtful accounts	$ 59	$ 200	—	$ 259
Year ended December 31, 2004 Allowance for doubtful accounts	—	$ 59	—	$ 59

INDEX TO EXHIBITS

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	—	Fifth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of June 29, 2005 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated June 29, 2006, filed with the Commission on July 6, 2006).
3.3	—	Certificate of Limited Partnership of Crosstex Energy Services, L.P. (incorporated by reference to Exhibit 3.3 to our Registration Statement on Form S-1, file No. 333-97779).
3.4	—	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).
3.5	—	Certificate of Limited Partnership of Crosstex Energy GP, L.P. (incorporated by reference to Exhibit 3.5 to our Registration Statement on Form S-1, file No. 333-97779).
3.6	—	Agreement of Limited Partnership of Crosstex Energy GP, L.P., dated as of July 12, 2002 (incorporated by reference to Exhibit 3.6 to our Registration Statement on Form S-1, file No. 333-97779).
3.7	—	Certificate of Formation of Crosstex Energy GP, LLC (incorporated by reference to Exhibit 3.7 to our Registration Statement on Form S-1, file No. 333-97779).
3.8	—	Amended and Restated Limited Liability Company Agreement of Crosstex Energy GP, LLC, dated as of December 17, 2002 (incorporated by reference to Exhibit 3.8 to our Registration Statement on Form S-1, file No. 333-97779).
4.1	—	Specimen Unit Certificate for Common Units (incorporated by reference to Exhibit 4.7 to Amendment No. 1 to our Registration Statement on Form S-3, file No. 333-128282).
4.2	—	Specimen Unit Certificate for the Senior Subordinated Series C Units (incorporated by reference to Exhibit 4.8 to our Registration Statement on Form S-3, file No. 333-135951).
4.3	—	Registration Rights Agreement, dated as of November 1, 2005, by and among Crosstex Energy, L.P., Kayne Anderson MLP Investment Company, Kayne Anderson Energy Total Return Fund, Inc., Tortoise Energy Capital Corp., Tortoise Energy Infrastructure Corporation and Fiduciary/Claymore MLP Opportunity Fund (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated November 1, 2005, filed with the Commission on November 3, 2005).
4.4	—	Registration Rights Agreement, dated as of June 24, 2005, among Crosstex Energy, L.P., Kayne Anderson MLP Investment Company, Tortoise Energy Capital Corporation and Tortoise Energy Infrastructure Corporation (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated June 24, 2005, filed with the Commission on June 4, 2005).
4.6	—	Registration Rights Agreement, dated as of June 29, 2006, by and among Crosstex Energy L.P., Chieftain Capital Management, Inc., Energy Income and Growth Fund, Fiduciary/Claymore MLP Opportunity Fund, Kayne Anderson MLP Investment Company, Kayne Anderson Energy Total Return Fund, Inc., LBI Group Inc., Tortoise Energy Infrastructure Corporation, Lubar Equity Fund, LLC and Crosstex Energy, Inc. (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated June 29, 2006, filed with the Commission on July 6, 2006).
10.1	—	Fourth Amended and Restated Credit Agreement, dated November 1, 2005, among Crosstex Energy Services, L.P., Bank of America, N.A. and certain other parties (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated November 1, 2005, filed with the Commission on November 3, 2005).
10.2	—	First Amendment to Fourth Amended and Restated Credit Agreement, dated as of February 24, 2006, among Crosstex Energy, L.P., Bank of America, N.A. and certain other parties (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K dated March 13, 2006, filed with the Commission on March 16, 2006).

Number		Description
10.3	—	Second Amendment to Fourth Amended and Restated Credit Agreement, dated as of June 29, 2006, among Crosstex Energy, L.P., Bank of America, N.A. and certain other parties (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated June 29, 2006, filed with the Commission on July 6, 2006).
10.4	—	Amended and Restated Note Purchase Agreement, dated as of July 25, 2006, among Crosstex Energy, L.P. and the Purchasers listed on the Purchaser Schedule attached thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated July 25, 2006, filed with the Commission on July 28, 2006).
10.5	—	Purchase and Sale Agreement, dated as of May 1, 2006, by and between Crosstex Energy Services, L.P., Chief Holdings LLC and the other parties named therein (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated May 1, 2006, filed with the Commission on May 4, 2006).
10.6†	—	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).
10.7	—	Amendment to Crosstex Energy GP, LLC Long-Term Incentive Plan, dated May 2, 2005 (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated May 2, 2005, filed with the Commission on May 6, 2005).
10.8	—	Omnibus Agreement, dated December 17, 2002, among Crosstex Energy, L.P. and certain other parties (incorporated by reference to Exhibit 10.5 to our Annual Report on Form 10-K for the year ended December 31, 2002).
10.9†	—	Form of Employment Agreement (incorporated by reference to Exhibit 10.6 to our Annual Report on Form 10-K for the year ended December 31, 2002).
10.10	—	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).
10.11	—	Senior Subordinated Series C Unit Purchase Agreement, dated as of May 16, 2006, by and among Crosstex Energy, L.P. and each of the Purchasers set forth on Schedule A thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated May 16, 2006, filed with the Commission on May 17, 2006).
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

Exhibit 21.1

LIST OF SUBSIDIARIES

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
Crosstex Pelican, LLC	Delaware
Crosstex Processing Services, LLC	Delaware
Crosstex NGL Marketing, L.P.	Texas
Sabine Pass Plant Facility, J.V.	Texas

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

The Partners
Crosstex Energy, L.P.

We consent to the incorporation by reference in the registration statements No. 333-116538, 333-128282, 333-134712 and 333-135951 on Forms S-3 and Forms S-8 of Crosstex Energy, L.P. and subsidiaries (No. 333-107025 and 333-127645) of our reports dated February 28, 2007, with respect to the consolidated balance sheets of Crosstex Energy, L.P. and subsidiaries as of December 31, 2006 and 2005, 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, 2006, and all related financial statement schedules, management's assessment of the effectiveness of internal control over financial reporting as of December 31, 2006 and the effectiveness of internal control over financial reporting as of December 31, 2006, which reports appear in the December 31, 2006 annual report on Form 10-K of Crosstex Energy, L.P. and subsidiaries.

As discussed in Note 2 to the consolidated financial statements, effective January 1, 2006, Crosstex Energy, L.P. and subsidiaries adopted the provisions of Statement of Financial Accounting Standards No. 123 (revised 2004), Share Based Payment.

/s/ KPMG LLP

Dallas, TX
February 28, 2007

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 current report on Form 10-K of Crosstex Energy, L.P.;

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

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

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) 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 the 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 generally 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 case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

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

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

/s/ Barry E. Davis

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

Date: February 28, 2007

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 current report on Form 10-K of Crosstex Energy, L.P.;

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

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

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) 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 the 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 generally 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 case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

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

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

/s/ William W. Davis

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

Date: February 28, 2007

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, 2006 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each of the undersigned, Barry E. Davis, Chief Executive Officer of Crosstex Energy GP, LLC, and William W. Davis, Chief Financial Officer of Crosstex Energy GP, LLC, certifies, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

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

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

/s/ Barry E. Davis
Barry E. Davis
President and Chief Executive Officer

February 28, 2007

/s/ William W. Davis
William W. Davis
Executive Vice President and Chief Financial Officer

February 28, 2007

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.