Compression. Gathering systems are operated at pressures that will maximize the total natural gas throughput from all connected wells. Because wells produce gas at progressively lower field pressures as they age, it becomes increasingly difficult to deliver the remaining production in the ground against the higher pressure that exists in the connected gathering system. Natural gas compression is a mechanical process in which a volume of gas at an existing pressure is compressed to a desired higher pressure, allowing gas that no longer naturally flows into a higher-pressure downstream pipeline to be brought to market. Field compression is typically used to allow a gathering system to operate at a lower pressure or provide sufficient discharge pressure to deliver gas into a higher-pressure downstream pipeline. The remaining natural gas in the ground will not be produced if field compression is not installed because the gas will be unable to overcome the higher gathering system pressure. In contrast, a declining well can continue delivering natural gas if the field compression is installed.

Natural gas processing. The principal components of natural gas are methane and ethane, but most natural gas also contains varying amounts of heavier NGLs and contaminants, such as water and CO_2, sulfur compounds, nitrogen or helium. Natural gas produced by a well may not be suitable for long-haul pipeline transportation or commercial use and may need to be processed to remove the heavier hydrocarbon components and contaminants. Natural gas in commercial distribution systems mostly consists of methane and ethane, and moisture and other contaminants have been removed so there are negligible amounts of them in the gas stream. Natural gas is processed to remove unwanted contaminants that would interfere with pipeline transportation or use of the natural gas and to separate those hydrocarbon liquids from the gas that have higher value as NGLs. The removal and separation of individual hydrocarbons through processing is possible due to 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 and the removal of contaminants.

NGL fractionation. NGLs are separated into individual, more valuable components during the fractionation process. NGL fractionation facilities separate mixed NGL streams into discrete NGL products: ethane, propane, isobutane, normal butane, natural gasoline and stabilized condensate. Ethane is primarily used in the petrochemical industry as feedstock for ethylene, one of the basic building blocks for a wide range of plastics and other chemical products. Propane is used as a petrochemical feedstock in the production of ethylene and propylene and as a heating fuel, an engine fuel and industrial fuel. Isobutane is used principally to enhance the octane content of motor gasoline. Normal butane is used as a petrochemical feedstock in the production of ethylene and butylene (a key ingredient in synthetic rubber), as a blend stock for motor gasoline and to derive isobutene through isomerization. Natural gasoline, a mixture of pentanes and heavier hydrocarbons, is used primarily as motor gasoline blend stock or petrochemical feedstock.

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.

Crude oil terminals. Crude oil rail terminals are an integral part of ensuring the movement of new crude oil production from the developing shale plays in the United States and Canada. In general, the crude oil rail unloading terminals are used to unload rail cars, store crude oil volumes for 3rd parties until the oil is re-delivered to premium markets via pipelines, trucks or rail to delivery points.

Balancing Supply and Demand

When the Partnership purchases natural gas, it establishes a margin normally by selling it for physical delivery to third-party users. It can also use over-the-counter derivative instruments or enter into future delivery obligations under futures contracts on the NYMEX. Through these transactions, the Partnership seeks to maintain a position that is balanced between purchases, on the one hand, and sales or future delivery obligations, on the other hand. Its policy is not to acquire and hold natural gas futures contracts or derivative products for the purpose of speculating on price changes.

Competition

The business of providing gathering, transmission, processing and marketing services for natural gas and NGLs is highly competitive. The Partnership faces strong competition in obtaining natural gas supplies and in the marketing and transportation of natural gas and NGLs. Its competitors include major integrated and independent E&P oil companies, natural gas producers, 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 the Partnership's competitors offer more services or have greater financial resources and access to larger natural gas supplies than it does. The Partnership's competition varies in different geographic areas.

In marketing natural gas and NGLs, the Partnership has numerous competitors, including marketing affiliates of interstate pipelines, major integrated oil and gas companies, and local and national natural gas producers, 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 the Partnership's marketing operations.

The Partnership faces 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 its competitors have greater financial resources or lower cost of capital, or are willing to accept lower returns or greater risks. The Partnership's competition differs by region and by the nature of the business or the project involved.

Natural Gas Supply

The Partnership's gathering and transmission pipelines have connections with major intrastate and interstate pipelines, which it believes have ample natural gas supplies in excess of the volumes required for the operation of these systems. The Partnership evaluates well and reservoir data that is either publicly available or furnished by producers or other service providers in connection with the construction and acquisition of its gathering systems 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 investment. Based on these facts, the Partnership believes that there should be adequate natural gas supply to recoup its investment with an adequate rate of return. The Partnership does not routinely obtain independent evaluations of reserves dedicated to its systems due to the cost and relatively limited benefit of such evaluations. Accordingly, it does not have estimates of total reserves dedicated to its systems or the anticipated life of such producing reserves.

Credit Risk and Significant Customers

The Partnership is diligent in attempting to ensure that it issues credit to only credit-worthy customers. However, the purchase and resale of gas exposes it 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 overall profitability.

During the year ended December 31, 2011, the Partnership had only one customer, Dow Hydrocarbons & Resources LLC, that represented greater than 10.0% of its revenue. While this customer represented 12.3% of consolidated revenues, the loss of this customer would not have a material impact on results of operations because the gross operating margins received from transactions with this customer are not material to the Partnership's total gross operating margin, and the Partnership believes the sales to this customer could be replaced with other buyers at comparable sales prices.

Regulation

Regulation by FERC of Interstate Natural Gas Pipelines. The Partnership does not own any interstate natural gas pipelines, so the Federal Energy Regulatory Commission, or FERC, does not directly regulate its operations under the National Gas Act, or NGA. However, FERC's regulation of interstate natural gas pipelines influences certain aspects of the Partnership's business and the market for its 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.

While the Partnership does not own any interstate pipelines, it does transport gas in interstate commerce. The rates, terms and conditions of service under which the Partnership transports natural gas in its pipeline systems in interstate commerce are subject to FERC jurisdiction under Section 311 of the Natural Gas Policy Act, or NGPA. In addition, FERC has adopted, or is in the process of adopting, various regulations concerning natural gas market transparency that will apply to some of the Partnership's pipeline operations. The maximum 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. The inability to obtain approval of rates at acceptable levels could result in refund obligations, the inability to achieve adequate returns on investments in new facilities and the deterrence of future investment or growth of the regulated facilities.

Regulation by FERC of Interstate NGL Pipelines. As of December 31, 2011, the Partnership did not own any interstate NGL pipelines. However, as discussed in "Recent Growth Developments," the Partnership intends to begin construction in 2012 of an expansion of the Cajun-Sibon NGL pipeline that is connected to its fractionation facilities in south central Louisiana. This expansion is scheduled to be operational in the first half of 2013. Once operational, the expansion will be subject to regulation by FERC as a common carrier under the Interstate Commerce Act, the Energy Policy Act of 1992 and related rules and orders. FERC regulation requires that interstate oil pipeline rates, including rates for transportation of NGLs, be filed with FERC and that these rates be "just and reasonable" and not unduly discriminatory.

Rates of interstate NGL pipelines are currently regulated by FERC primarily through an annual indexing methodology, under which pipelines increase or decrease their rates in accordance with an index adjustment specified by FERC. For the five-year period beginning in 2010, FERC established an annual index adjustment equal to the change in the producer price index for finished goods plus 2.65%. This adjustment is subject to review every five years. Under FERC's regulations, an NGL pipeline can request a rate increase that exceeds the rate obtained through application of the indexing methodology by using a cost-of-service approach, but only after the pipeline establishes that a substantial divergence exists between the actual costs experienced by the pipeline and the rates resulting from application of the indexing methodology.

The Interstate Commerce Act permits interested persons to challenge proposed new or changed rates and authorizes FERC to suspend the effectiveness of such rates for up to seven months and investigate such rates. If, upon completion of an investigation, FERC finds that the new or changed rate is unlawful, it is authorized to require the pipeline to refund revenues collected in excess of the just and reasonable rate during the term of the investigation. The just and reasonable rate used to calculate refunds cannot be lower than the last tariff rate approved as just and reasonable. FERC may also investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Upon an appropriate showing, a shipper may obtain reparations for charges in excess of a just and reasonable rate for a period of up to two years prior to the filing of a complaint.

Intrastate Pipeline Regulation. The Partnership's intrastate natural gas pipeline operations 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. The Partnership owns a number of natural gas pipelines that it believes 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.

The Partnership is subject to some 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 the Partnership sells natural gas currently is not subject to federal regulation and, for the most part, is not subject to state regulation. Its natural gas sales 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 Partnership cannot predict the ultimate impact of these regulatory changes on its natural gas marketing operations, but does not believe that it will be affected by any such FERC action in a manner that is materially different from the natural gas marketers with whom it competes.

Environmental Matters

General. The Partnership's operation of processing and fractionation plants, pipelines and associated facilities in connection with the gathering and processing 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 the Partnership's overall costs of doing business, including costs of planning, constructing, and operating plants, pipelines, and other facilities.

Included in the Partnership's construction and operation costs are capital cost items necessary to maintain or upgrade equipment and facilities. Similar costs are likely upon changes in laws or regulations and upon any future acquisition of operating assets.

Any failure to comply with applicable environmental laws and regulations, including those relating to equipment failures and 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. We believe that the Partnership currently holds all material governmental approvals required to operate its major facilities. As part of the regular evaluation of its operations, the Partnership routinely reviews and updates governmental approvals as necessary. We believe that the Partnership's operations and facilities are in substantial compliance with applicable environmental laws and regulations and that the cost of compliance with such laws and regulations currently in effect will not have a material adverse effect on its 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 the Partnership's possible future operations, and we cannot assure you that the Partnership will not incur significant costs and liabilities, including those relating to claims for damage to property and persons as a result of any such upsets, releases, or spills. In the event of future increases in environmental costs, the Partnership may be unable to pass on those cost increases to its customers. A discharge of hazardous substances or wastes into the environment could, to the extent losses related to the event are not insured, subject the Partnership to substantial expense, including both the cost to comply with applicable laws and regulations and to pay fines or penalties that may be assessed and the cost related to claims made by neighboring landowners and other third parties for personal injury or damage to natural resources or property. The Partnership 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 with respect to more stringent future laws and regulations or more rigorous enforcement of existing laws and regulations.

Hazardous Substances and Waste. To a large extent, the environmental laws and regulations affecting the Partnership's operations relate to the release of hazardous substances or solid wastes into soils, groundwater and surface water, and include measures to prevent and control pollution. 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. Potentially liable 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 potentially 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 ordinary operations, the Partnership may generate wastes that may fall within the definition of a "hazardous substance." In addition, there are other laws and regulations that can create liability for releases of petroleum, natural gas or NGLs. Moreover, the Partnership may be responsible under CERCLA or other laws for all or part of the costs required to clean up sites at which such wastes have been disposed. The Partnership has not received any notification that it may be potentially responsible for cleanup costs under CERCLA or any analogous federal or state laws.

The Partnership also generates, 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/or comparable state statutes. From time to time, the Environmental Protection Agency, or EPA, and state regulatory agencies have considered the adoption of stricter disposal standards for nonhazardous wastes, including crude oil and natural gas wastes. Moreover, it is possible that some wastes generated by it that are currently considered as nonhazardous may in the future be designated as "hazardous wastes," resulting in the wastes being subject to more rigorous and costly management and disposal requirements. Changes in applicable laws or regulations may result in an increase in the Partnership's capital expenditures or plant operating expenses or otherwise impose limits or restrictions on its production and operations.

The Partnership currently owns or leases, and has in the past owned or leased, and in the future 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 the Partnership during the operating history of those facilities. In addition, a number of these properties may have been operated by third parties over whom the Partnership 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, the Partnership could be required to remove or remediate previously disposed wastes or property contamination if present, including groundwater contamination, or to take action to prevent future contamination.

Air Emissions. The Partnership's current and future operations are subject to the federal Clean Air Act and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including the Partnership's facilities, and impose various controls together with monitoring and reporting requirements. Pursuant to these laws and regulations, the Partnership may be required to obtain environmental agency pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in an increase in existing air emissions, obtain and comply with the terms of air permits, which include various emission and operational limitations, or use specific emission control technologies to limit emissions. The Partnership likely will be required to incur certain capital expenditures in the future for air pollution control equipment in connection with maintaining or obtaining governmental approvals addressing air-emission related issues. 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 such requirements will not have a material adverse effect on the Partnership's financial condition or operating results, and the requirements are not expected to be more burdensome to the Partnership than any similarly situated company.

Air emissions associated with operations in the Barnett Shale area have come under recent scrutiny. In 2010 and 2011, the Texas Commission on Environmental Quality (TCEQ) conducted comprehensive monitoring of air emissions in the Barnett Shale area, in response to public concerns about high concentrations of benzene and other potential emissions in the air near drilling sites and natural gas processing facilities. In addition, environmental groups have advocated increased regulation in the Barnett Shale area and these groups as well as at least one state representative further advocated a moratorium on permits for new gas wells until TCEQ completes its analysis. Also, the EPA entered into a settlement in 2010 that required it to reevaluate regulations for the control of air emissions from the oil and natural gas industry. As a result, the EPA proposed regulations in July 2011, which are currently pending adoption, that would establish new air pollution standards for the oil and natural gas industry, including new source performance standards for volatile organic compounds and sulfur dioxide and an air toxics standard for oil and natural gas production and for natural gas transmission and storage. Changes in laws or regulations imposing emission limitations, pollution control technology requirements or other regulatory requirements or any restriction on permitting of natural gas production facilities in the Barnett Shale area could have an adverse effect on the Partnership's business.

Climate Change. In response to concerns suggesting that emissions of certain gases, commonly referred to as "greenhouse gases" (including carbon dioxide and methane), may be contributing to warming of the earth's atmosphere, EPA is taking steps that would result in the regulation of greenhouse gases as pollutants under the federal Clean Air Act.

In October 2009, EPA promulgated its Mandatory Reporting Rule for greenhouse gases, which requires the monitoring and reporting of greenhouse gas emissions on an annual basis. All of the Partnership's facilities operating combustion sources, such as engines, or natural gas fractionation facilities are subject to the greenhouse gas reporting requirements included in the October 2009 final rule. The first annual greenhouse gas emissions inventory for Crosstex affected facilities was filed by Crosstex in September 2011. In November 2010 and further in December 2011, EPA expanded the scope of the Mandatory Reporting Rule to include petroleum and natural gas pipeline systems, which applies the Mandatory Reporting Rule's requirements to, among other sources, fugitive and vented methane emissions from the oil and gas sector, including natural gas transmission compression. The Partnership's transmission compression facilities as well as gathering compressor stations with large amine treating capacities are now required to report under this expanded rule, with the first report due to the EPA on September 28, 2012. Although the Mandatory Reporting Rule does not control greenhouse gas emission levels from any facilities, it has still caused the Partnership to incur monitoring and reporting costs for emissions that are subject to the rule. Further, the rule's new requirements for reporting of fugitive and vented methane emissions from the oil and gas industry can be expected to increase our monitoring and reporting costs from here on forward.

After a series of regulatory actions finalized by EPA between December 2009 and May 2010, greenhouse gases became pollutants "subject to regulation" under the Clean Air Act's Prevention of Significant Deterioration (PSD) air quality permit program for stationary sources, and the largest of these sources have also become subject to permitting requirements under the Clean Air Act's Title V permitting program. As a result, new major stationary sources of greenhouse gas emissions, and modifications of existing major stationary sources that significantly increase their greenhouse gas emissions will require a permit setting forth Best Available Control Technology (BACT) for those emissions. EPA has, through its "Tailoring Rule," acted to limit these permitting requirements to only the largest sources of greenhouse gas emissions initially, but these new requirements could in the future affect its operations and its ability to obtain air permits for new or modified facilities.

The U.S. Congress has also considered legislation to mandate reductions of greenhouse gas emissions, and almost half of the states, either individually or through multi-state regional initiatives, have already taken legal measures intended to reduce greenhouse gas emissions, primarily through the planned development of greenhouse gas emission inventories and/or greenhouse gas cap and trade programs.

Because regulation of Green House Gas ("GHG") emissions is relatively new, further regulatory, legislative and judicial developments are likely to occur. Such developments may affect how these GHG initiatives will impact the Partnership. In addition to these regulatory developments, recent judicial decisions have allowed certain tort claims alleging property damage to proceed against GHG emissions sources may increase its litigation risk for such claims. Due to the uncertainties surrounding the regulation of and other risks associated with GHG emissions, the Partnership cannot predict the financial impact of related developments on the Partnership.

Federal or state legislative or regulatory initiatives that regulate or restrict emissions of greenhouse gases in areas in which the Partnership conducts business could adversely affect the demand for the products it stores, transports, and processes, and depending on the particular program adopted could increase the costs of its operations, including costs to operate and maintain its facilities, install new emission controls on its facilities, acquire allowances to authorize its greenhouse gas emissions, pay any taxes related to its greenhouse gas emissions and/or administer and manage a greenhouse gas emissions program. The Partnership may be unable to recover any such lost revenues or increased costs in the rates it charges its customers, and any such recovery may depend on events beyond its control, including the outcome of future rate proceedings before the FERC or state regulatory agencies and the provisions of any final legislation or regulations. Reductions in the Partnership's revenues or increases in its expenses as a result of climate control initiatives could have adverse effects on its business, financial position, results of operations and prospects.

Certain scientific studies on climate change suggest that stronger storms may occur in the future in certain of the areas in which the Partnership operates, although the scientific studies are not unanimous. Due to their location, the Partnership's operations along the Gulf Coast are vulnerable to operational and structural damages resulting from hurricanes and other severe weather systems and the Partnership's insurance may not cover all associated losses. The Partnership is taking steps to mitigate physical risks from storms, but no assurance can be given that future storms will not have a material adverse effect on its business.

Clean Water Act. The Federal Water Pollution Control Act, also known as the Clean Water Act, and comparable 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. The Partnership believes that it is 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 its results of operations.

It is customary to recover natural gas from deep shale formations through the use of hydraulic fracturing, combined with sophisticated horizontal drilling. Hydraulic fracturing is an important and commonly used process in the completion of wells by the Partnership's customers. Hydraulic fracturing involves the injection of water, sand and chemical additives under pressure into rock formations to stimulate gas production. Due to public concerns raised regarding potential impacts of hydraulic fracturing on groundwater quality, legislative and regulatory efforts at the federal level and in some states have been initiated to require or make more stringent the permitting and other regulatory requirements for hydraulic fracturing operations. At the federal level, the U.S. Congress has introduced legislation that would amend the federal Safe Drinking Water Act to subject hydraulic fracturing operations to regulation under that Act and to require the disclosure of chemicals used by the oil and gas industry in the hydraulic fracturing process. As support for the chemical disclosure requirements included in the legislation, sponsors of the legislation asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. Disclosure of chemicals used in the fracturing process could make it easier for third parties opposing hydraulic fracturing to initiate legal proceedings against producers and service providers based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. If adopted, this or other similar legislation could establish an additional level of regulation and permitting of hydraulic fracturing operations at the federal level, which could lead to operational delays, increased operating costs and additional regulatory burdens that could make it more difficult for the Partnership's customers to perform hydraulic fracturing. In addition, during the first quarter of 2010, the EPA initiated a detailed scientific study of hydraulic fracturing and its potential impacts on surface and ground waters. The initial study results are expected to be available in late 2012. In early 2010, EPA also indicated in a website posting that it intended to regulate hydraulic fracturing under the Safe Drinking Water Act and require permitting for any well where hydraulic fracturing was conducted with the use of diesel as an additive. While industry groups have challenged EPA's website posting as improper rulemaking, the Agency's position, if upheld could require additional permitting and could lead to operations delays, increased costs and regulatory burdens that could make it more difficult for the Partnership's customers to perform hydraulic fracturing. State and local governments have also considered proposed regulations addressing public concerns related to hydraulic fracturing operations. Some state and local governments in regions where shale development is underway have considered or imposed moratoriums on drilling operations using hydraulic fracturing until further study of the potential environmental and human health impacts by EPA or the relative state agencies are completed. Any increased federal, state or local regulation could reduce the volumes of natural gas that the Partnership's customers move through its gathering systems which would materially adversely affect its revenues and results of operations.

Employee Safety. The Partnership is 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. The Partnership believes that its operations are in substantial compliance with the OSHA requirements, including general industry standards, record keeping requirements, and monitoring of occupational exposure to regulated substances.

DOT Safety Regulations. The Partnership's pipelines are subject to regulation by the U.S. Department of Transportation (DOT). DOT's Pipeline Hazardous Material Safety Administration (PHMSA), acting through the Office of Pipeline Safety (OPS), administers the national regulatory program to assure the safe transportation of natural gas, petroleum, and other hazardous materials by pipeline. OPS develops regulations and other approaches to risk management to assure safety in design, construction, testing, operation, maintenance, and emergency response of pipeline facilities. These safety regulations are listed under 49 CFR, Parts 192 and 195. Pipelines that transport natural gas are governed under 49 CFR 192. Pipelines that transport crude oil, carbon dioxide, NGL and petroleum products are governed under 49 CFR 195. PHMSA requires any entity which owns or operates pipeline facilities to comply with the regulations under these and referenced regulations, regarding 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, amendments to 49 CFR Part 192 and 195 (PIM) requires operators of 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. On December 13, 2011, the Senate passed, and on January 3, 2012, the President signed into law, H.R. 2845, "Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011," which increases potential penalties for pipeline safety violations, gives new rulemaking authority to the DOT with respect to shut-off valves on transmission pipeline facilities constructed or entirely replaced after the rule is promulgated, requires DOT to revise incident notification guidance, and imposes new records requirements on pipeline owners and operators. The new legislation also requires the DOT to study and report to Congress on other areas of pipeline safety, including expanding the reach of the integrity management regulations beyond high consequences areas, but restricts DOT from promulgating expanded integrity management rules during the review period and for a period following submittal of its report to Congress unless the rulemaking is needed to address a present condition that poses a risk to public safety, property, or the environment. In addition to federal regulations, the Railroad Commission of Texas, or TRRC, regulates the Partnership's pipelines in Texas under its own pipeline safety regulations, including integrity management rules. The Partnership believes that its pipeline operations are in substantial compliance with applicable PHMSA and TRRC 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 PHMSA or TRRC requirements will not have a material adverse effect on the Partnership's results of operations or financial positions.

Office Facilities

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 25,100 square feet of office space for the Partnership's Louisiana operations in Houston, Texas with lease terms expiring in April 2023. We have approximately 17,000 square feet of office space in Fort Worth, Texas with lease terms expiring in April 2013 and currently have this space sub-leased to other tenants.

Employees

As of December 31, 2011, the Partnership (through its subsidiaries) employed approximately 494 full-time employees. Approximately 179 of the employees were general and administrative, engineering, accounting and commercial personnel and the remainder were operational employees. The Partnership is not party to any collective bargaining agreements, and has not had any significant labor disputes in the past. We believe that the Partnership has good relations with its 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 occur, our business, financial condition or results of operations could be affected materially and adversely. In that case, we may be unable to pay dividends to our shareholders and the trading price of our common share 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.

Our cash flow consists almost exclusively of distributions from Crosstex Energy, L.P.

Our only cash-generating assets are our partnership interests in Crosstex Energy, L.P. Our cash flow is therefore completely dependent upon the ability of the Partnership to make distributions to its partners. The amount of cash that the Partnership can distribute to its partners, including us, each quarter principally depends upon the amount of cash it generates from its operations, which will fluctuate from quarter to quarter based on, among other things:

- the amount of natural gas transported in its gathering and transmission pipelines;
- the level of the Partnership's processing operations;

- the fees the Partnership charges and the margins it realizes for its services;
- the price of natural gas;
- the relationship between natural gas and NGL prices; and
- its level of operating costs.

In addition, the actual amount of cash the Partnership will have available for distribution will depend on other factors, some of which are beyond its control, including:

- the level of capital expenditures the Partnership makes;
- the cost of acquisitions, if any;
- its debt service requirements;
- fluctuations in its working capital needs;
- its ability to make working capital borrowings under its bank credit facility to pay distributions;
- prevailing economic conditions; and
- the amount of cash reserves established by the general partner in its sole discretion for the proper conduct of its business.

Because of these factors, the Partnership may not be able, or may not have sufficient available cash to pay distributions to unitholders each quarter. Furthermore, you should also be aware that the amount of cash the Partnership has available for distribution depends primarily upon its cash flow, including cash flow from financial reserves and working capital borrowings, and is not solely a function of profitability, which will be affected by non-cash items. As a result, the Partnership may make cash distributions during periods when it records losses and may not make cash distributions during periods when it records net income.

We are largely prohibited from engaging in activities that compete with the Partnership.

So long as we own the general partner of the Partnership, we are prohibited by an omnibus agreement with the Partnership from engaging in the business of gathering, transmitting, treating, processing, storing and marketing natural gas and transporting, fractionating, storing and marketing NGLs, except to the extent that the Partnership, with the concurrence of its independent directors comprising its conflicts committee, elects not to engage in a particular acquisition or expansion opportunity. This exception for competitive activities is relatively limited. Although we have no current intention of pursuing the types of opportunities that we are permitted to pursue under the omnibus agreement such as competitive opportunities that the Partnership declines to pursue or permitted activities that are not in competition with the Partnership, the provisions of the omnibus agreement may, in the future, limit activities that we would otherwise pursue.

In our corporate charter, we have renounced business opportunities that may be pursued by the Partnership or by certain stockholders.

In our restated charter and in accordance with Delaware law, we have renounced any interest or expectancy we may have in, or in being offered an opportunity to participate in, any business opportunities, including any opportunities within those classes of opportunity currently pursued by the Partnership, presented to:

- persons who are officers or directors of the company or who, on October 1, 2003, were, and at the time of presentation are, stockholders of the company (or to persons who are affiliates or associates of such officers, directors or stockholders), if the company is prohibited from participating in such opportunities by the omnibus agreement; or

- any investment fund sponsored or managed by Yorktown Partners LLC, including any fund still to be formed, or to any of our directors who is an affiliate or designate of these entities.

As a result of this renunciation, these officers, directors and stockholders should not be deemed to be breaching any fiduciary duty to us if they or their affiliates or associates pursue opportunities presented as described above.

Although we control the Partnership, the general partner owes fiduciary duties to the Partnership and the unitholders.

Conflicts of interest exist and may arise in the future as a result of the relationship between us and our affiliates, including the general partner, on the one hand, and the Partnership and its limited partners, on the other hand. The directors and officers of Crosstex Energy GP, LLC have fiduciary duties to manage the general partner in a manner beneficial to us, its owner. At the same time, the general partner has a fiduciary duty to manage the Partnership in a manner beneficial to the Partnership and its limited partners. The board of directors of Crosstex Energy GP, LLC will resolve any such conflict and has broad latitude to consider the interests of all parties to the conflict. The resolution of these conflicts may not always be in our best interest or that of our stockholders.

For example, conflicts of interest may arise in the following situations:

- the allocation of shared overhead expenses to the Partnership and us;
- the interpretation and enforcement of contractual obligations between us and our affiliates, on the one hand, and the Partnership, on the other hand, including obligations under the omnibus agreement;
- the determination of the amount of cash to be distributed to the Partnership's partners and the amount of cash to be reserved for the future conduct of the Partnership's business;
- the determination whether to make borrowings under the capital facility to pay distributions to partners; and
- any decision we make in the future to engage in activities in competition with the Partnership as permitted under our omnibus agreement with the Partnership.

If the general partner is not fully reimbursed or indemnified for obligations and liabilities it incurs in managing the business and affairs of the Partnership, its value, and therefore the value of our common stock, could decline.

The general partner may make expenditures on behalf of the Partnership for which it will seek reimbursement from the Partnership. In addition, under Delaware partnership law, the general partner, in its capacity as the general partner of the Partnership, has unlimited liability for the obligations of the Partnership, such as its debts and environmental liabilities, except for those contractual obligations of the Partnership that are expressly made without recourse to the general partner. To the extent the general partner incurs obligations on behalf of the Partnership, it is entitled to be reimbursed or indemnified by the Partnership. In the event that the Partnership is unable or unwilling to reimburse or indemnify the general partner, the general partner may be unable to satisfy these liabilities or obligations, which would reduce its value and therefore the value of our common stock.

Risks Inherent in the Partnership's Business

The Partnership's profitability is dependent upon prices and market demand for natural gas and NGLs, which are beyond its control and have been volatile.

The Partnership is subject to significant risks due to fluctuations in commodity prices. The Partnership is directly exposed to these risks primarily in the gas processing component of its business. For the year ended December 31, 2011 approximately 10.7% of its total gross operating margin was generated under percent of liquids (POL) contracts. Under these contracts the Partnership receives a fee in the form of a percentage of the liquids recovered and the producer bears all the cost of the natural gas shrink. Accordingly, the Partnership's revenues under these contracts are directly impacted by the market price of NGLs.

The Partnership also realizes processing gross operating margins under processing margin (margin) contracts. For the year ended December 31, 2011 approximately 19.3% of the Partnership's total gross operating margin was generated under processing margin contracts. The Partnership has a number of processing margin contracts with the Partnership's Plaquemine, Gibson, Eunice, Bluewater, and Pelican processing plants. Under this type of contract, the Partnership pays the producer for the full amount of inlet gas to the plant, and it makes 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") and the cost of fuel used in processing. The shrink and fuel losses are referred to as plant thermal reduction or PTR. The Partnership's margins from these contracts can be greatly reduced or eliminated during periods of high natural gas prices relative to liquids prices.

The Partnership is also indirectly exposed to commodity prices due to the negative impacts on production and the development of production of natural gas and NGLs connected to or near its assets and on its margins for transportation between certain market centers. Low prices for these products will reduce the demand for the Partnership's services and volumes on its systems.

In the past, the prices of natural gas and NGLs have been extremely volatile and the Partnership expects this volatility to continue. For example, prices of natural gas in 2011 were below the market price realized throughout most of 2010 while prices for oil and NGLs were higher than 2010 market prices. Crude oil prices (based on the New York Mercantile Exchange (the "NYMEX") futures daily close prices for the prompt month) in 2011 ranged from a low of $75.67 per Bbl in October 2011 to a high of $113.93 per Bbl in April 2011. Weighted average NGL prices in 2011 (based on the Oil Price Information Service (OPIS) Napoleonville daily average spot liquids prices) ranged from a low of $0.99 per gallon in February 2011 to a high of $1.35 per gallon in May 2011. Natural gas prices (based on Gas Daily Henry Hub closing prices) during 2011 ranged from a high of $4.92 per MMBtu in June 2011 to a low of $2.79 per MMBtu in November 2011.

The markets and prices for natural gas and NGLs depend upon factors beyond the Partnership's control. These factors include the supply and 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;
- technology, including improved production techniques (particularly with respect to shale development);
- the level of domestic industrial and manufacturing activity;
- the availability of imported oil, natural gas and NGLs;
- international demand for oil and NGLs;

- actions taken by foreign oil and gas producing nations;
- the availability of local, intrastate and interstate transportation systems;
- the availability of downstream NGL fractionation facilities;
- the availability and marketing of competitive fuels;
- the impact of energy conservation efforts; and
- the extent of governmental regulation and taxation, including the regulation of "greenhouse gases."

Changes in commodity prices may also indirectly impact the Partnership's profitability by influencing drilling activity and well operations, and thus the volume of gas it gathers and processes. The volatility in commodity prices may cause the Partnership's gross operating margin and cash flows to vary widely from period to period. The Partnership's hedging strategies may not be sufficient to offset price volatility risk and, in any event, do not cover all of its throughput volumes. Moreover, hedges are subject to inherent risks, which we describe in "Item 7A. Quantitative and Qualitative Disclosure about Market Risk." The Partnership's use of derivative financial instruments does not eliminate its exposure to fluctuations in commodity prices and interest rates and has in the past and could in the future result in financial losses or reduced income. For a discussion of the Partnership's risk management activities, please read "Item 7A. Quantitative and Qualitative Disclosure about Market Risk."

The Partnership's substantial indebtedness could limit its flexibility and adversely affect its financial health.

The Partnership has a substantial amount of indebtedness. As of December 31, 2011, the Partnership had approximately $713.4 million of indebtedness outstanding primarily comprised of $725.0 million (including $11.6 million of original issue discount) of senior unsecured notes. As of December 31, 2011, there was $85.0 million of borrowing and $69.0 million in outstanding letters of credit, under the bank credit facility leaving approximately $331.0 million available for future borrowing based on a borrowing capacity of $485.0 million. Based on the January amendment to increase the credit facility borrowing capacity to $635.0 million and borrowings outstanding as of December 31, 2011, the Partnership's available borrowing would be $481.0 million.

The Partnership's substantial indebtedness could limit its flexibility and adversely affect its financial health. For example, it could:

- make the Partnership more vulnerable to general adverse economic and industry conditions;
- require the Partnership to dedicate a substantial portion of its cash flow from operations to payments on its indebtedness, thereby reducing the availability of its cash flow for operations and other purposes;
- limit the Partnership's flexibility in planning for, or reacting to, changes in its business and the industry in which it operates; and
- place the Partnership at a competitive disadvantage compared to competitors that may have proportionately less indebtedness.

In addition, the Partnership's ability to make scheduled payments or to refinance its obligations depends on its successful financial and operating performance. The Partnership cannot assure you that its operating performance will generate sufficient cash flow or that its capital resources will be sufficient for payment of its debt obligations in the future. The Partnership's financial and operating performance, cash flow and capital resources depend upon prevailing economic conditions and certain financial, business and other factors, many of which are beyond its control.

If the Partnership's cash flow and capital resources are insufficient to fund its debt service obligations, the Partnership may be forced to sell material assets or operations, obtain additional capital or restructure its debt. In the event that the Partnership is required to dispose of material assets or operations or restructure its debt to meet its debt service and other obligations, it cannot assure you as to the terms of any such transaction or how quickly any such transaction could be completed, if at all.

The Partnership may not be able to access new capital to fund its acquisition and growth strategies which could impair its ability to fund future capital needs and to grow.

Global financial markets and economic conditions have been disrupted and volatile over the past several years. These conditions and current weak world economic conditions have made, and could in the future make, it difficult to obtain funding for its capital needs. As a result, the cost of raising money in the debt and equity capital markets could increase substantially while the availability of funds from those markets could diminish significantly. Due to these factors, the Partnership cannot be certain that new debt or equity financing will be available to it on acceptable terms or at all. Without adequate funding, the Partnership may be unable to execute its growth strategy, complete future acquisitions or future construction projects or other capital expenditures, take advantage of other business opportunities or respond to competitive pressures, any of which could have a material adverse effect on the Partnership's revenues and results of operations. Further, the Partnership's customers may increase collateral requirements from it, including letters of credit which reduce available borrowing capacity, or reduce the business they transact with the Partnership to reduce their credit exposure.

Due to the Partnership's lack of asset diversification, adverse developments in its gathering, transmission, processing and NGL services businesses would materially impact its financial condition.

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

The Partnership may not be successful in balancing its purchases and sales.

The Partnership is a party to certain long-term gas sales commitments that it satisfies through supplies purchased under long-term gas purchase agreements. When the Partnership enters into those arrangements, its sales obligations generally match its purchase obligations. However, over time the supplies that the Partnership has under contract may decline due to reduced drilling or other causes and it may be required to satisfy the sales obligations by buying additional gas at prices that may exceed the prices received under the sales commitments. In addition, a producer could fail to deliver contracted volumes or deliver in excess of contracted volumes, or a consumer could purchase more or less than contracted volumes. Any of these actions could cause the Partnership's purchases and sales not to be balanced. If the Partnership's purchases and sales are not balanced, it will face increased exposure to commodity price risks and could have increased volatility in its operating income.

The Partnership has made commitments to purchase natural gas in production areas based on production-area indices and to sell the natural gas into market areas based on market-area indices, pay the costs to transport the natural gas between the two points and capture the difference between the indices as margin. Changes in the index prices relative to each other (also referred to as basis spread) can significantly affect the Partnership's margins or even result in losses. For example, the Partnership is a party to one contract with a term to 2019 to supply approximately 150,000 MMBtu/day of gas. The Partnership buys gas for this contract on several different production-area indices on its NTP and sells the gas into a different market area index. For the year ended December 31, 2011 the Partnership has recorded a loss of approximately $13.3 million on this contract, and the Partnership currently expects that it will record a loss of approximately $13.0 million to $17.0 million on this contract in 2012. Reduced supplies and narrower basis spreads in recent periods have increased the losses on this contract, and greater losses on this contract could occur in future periods if these conditions persist or become worse. For additional information on this contract, please see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Overview."

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

The Partnership's gathering systems are connected to natural gas wells from which production will naturally decline over time, which means that its cash flows associated with these sources of natural gas will likely also decline over time. In order to maintain or increase throughput levels in its natural gas gathering systems and asset utilization rates at its processing plants and to fulfill its current sales commitments, the Partnership must continually contract for new natural gas supplies. The Partnership may not be able to obtain additional contracts for natural gas supplies. The primary factors affecting its ability to connect new wells to its gathering facilities include its success in contracting for existing natural gas supplies that are not committed to other systems and the level of drilling activity near its gathering systems. If the Partnership is unable to maintain or increase the throughput on its systems by accessing new natural gas supplies to offset the natural decline in reserves, the Partnership's business and financial results could be materially, adversely affected. In addition, the Partnership's future growth will depend in part upon whether it can contract for additional supplies at a greater rate than the rate of natural decline in the currently connected supplies.

Fluctuations in energy prices can greatly affect production rates and investments by third parties in the development of new oil and natural gas reserves. Natural gas prices were relatively low in 2011 and continue to be depressed. Prolonged periods of low natural gas prices may put downward pressure on future drilling activity which may result in lower volumes. Tax policy changes or additional regulatory restrictions on development could also have a negative impact on drilling activity, reducing supplies of natural gas available to the Partnership's systems. Additional governmental regulation of, or delays in issuance of permits for, the offshore exploration and production industry may negatively impact current and future volumes from offshore pipelines supplying its processing plants. The Partnership has no control over producers and depends on them to maintain sufficient levels of drilling activity. A material decrease in natural gas production or in the level of drilling activity in its principal geographic areas for a prolonged period, as a result of depressed commodity prices or otherwise, likely would have a material adverse effect on the Partnership's results of operations and financial position.

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

The Partnership is vulnerable to operational, regulatory and other risks due to its concentration of assets in south Louisiana and the Gulf of Mexico, including the effects of adverse weather conditions such as hurricanes.

The Partnership's operations and revenues will be significantly impacted by conditions in south Louisiana and the Gulf of Mexico because it has a significant portion of its assets located in these two areas. The Partnership's concentration of activity in Louisiana and the Gulf of Mexico makes it more vulnerable than many of its competitors to the risks associated with these areas, 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 the Partnership's operations could experience the same condition at the same time, these conditions could have a relatively greater impact on its results of operations than they might have on other midstream companies who have operations in more diversified geographic areas.

The Partnership's use of derivative financial instruments does not eliminate its exposure to fluctuations in commodity prices and interest rates and has in the past and could in the future result in financial losses or reduce its income.

The Partnership's operations expose it to fluctuations in commodity prices, and its credit facility exposes the Partnership to fluctuations in interest rates. The Partnership uses over-the-counter price and basis swaps with other natural gas merchants and financial institutions. Use of these instruments is intended to reduce its exposure to short-term volatility in commodity prices. As of December 31, 2011, the Partnership has hedged only portions of its expected exposures to commodity price risk. In addition, to the extent the Partnership hedges its commodity price risk using swap instruments, the Partnership will forego the benefits of favorable changes in commodity prices. Although the Partnership does not currently have any financial instruments to eliminate its exposure to interest rate fluctuations, the Partnership may use financial instruments in the future to offset its exposure to interest rate fluctuations.

Even though monitored by management, the Partnership's hedging activities may fail to protect it and could reduce its earnings and cash flow. The Partnership's hedging activity may be ineffective or adversely affect cash flow and earnings because, among other factors:

- hedging can be expensive, particularly during periods of volatile prices;
- the Partnership's counterparty in the hedging transaction may default on its obligation to pay or otherwise fail to perform; and
- available hedges may not correspond directly with the risks against which the Partnership seeks protection. For example:
  - the duration of a hedge may not match the duration of the risk against which the Partnership seeks protection;
  - variations in the index used to price a commodity hedge may not adequately correlate with variations in the index used to sell the physical commodity (known as basis risk); and
  - the Partnership may not produce or process sufficient volumes to cover swap arrangements it enters into for a given period. If its actual volumes are lower than the volumes it estimated when entering into a swap for the period, the Partnership might be forced to satisfy all or a portion of its derivative obligation without the benefit of cash flow from its sale or purchase of the underlying physical commodity, which could adversely affect liquidity.

The Partnership's financial statements may reflect gains or losses arising from exposure to commodity prices for which it is unable to enter into fully effective hedges. In addition, the standards for cash flow hedge accounting are rigorous. Even when the Partnership engages in hedging transactions that are effective economically, these transactions may not be considered effective cash flow hedges for accounting purposes. The Partnership's earnings could be subject to increased volatility to the extent its derivatives do not continue to qualify as cash flow hedges, and, if the Partnership assumes derivatives as part of an acquisition, to the extent the Partnership cannot obtain or chooses not to seek cash flow hedge accounting for the derivatives it assumes. Please read "Item 7A. Quantitative and Qualitative Disclosures about Market Risk" for a summary of the Partnership's hedging activities.

A reduction in demand for NGL products by the petrochemical, refining or other industries or by the fuel markets could materially adversely affect the Partnership's results of operations and financial condition.

The NGL products the Partnership produces have a variety of applications, including as heating fuels, petrochemical feedstocks and refining blend stocks. A reduction in demand for NGL products, whether because of general or industry specific economic conditions, new government regulations, global competition, reduced demand by consumers for products made with NGL products (for example, reduced petrochemical demand observed due to lower activity in the automobile and construction industries), increased competition from petroleum-based feedstocks due to pricing differences, mild winter weather for some NGL applications or other reasons, could result in a decline in the volume of NGL products the Partnership handles or reduce the fees the Partnership charges for its services. The Partnership's NGL products and the demand for these products are affected as follows:

- *Ethane.* Ethane is typically supplied as purity ethane or as part of ethane-propane mix. Ethane is primarily used in the petrochemical industry as feedstock for ethylene, one of the basic building blocks for a wide range of plastics and other chemical products. Although ethane is typically extracted as part of the mixed NGL stream at gas processing plants, if natural gas prices increase significantly in relation to NGL product prices or if the demand for ethylene falls, it may be more profitable for natural gas processors to leave the ethane in the natural gas stream thereby reducing the volume of NGLs delivered for fractionation and marketing.
- *Propane.* Propane is used as a petrochemical feedstock in the production of ethylene and propylene, as a heating, engine and industrial fuel, and in agricultural applications such as crop drying. Changes in demand for ethylene and propylene could adversely affect demand for propane. The demand for propane as a heating fuel is significantly affected by weather conditions. The volume of propane sold is at its highest during the six-month peak heating season of October through March. Demand for the Partnership's propane may be reduced during periods of warmer-than-normal weather.
- *Normal Butane.* Normal butane is used in the production of isobutane, as a refined product blending component, as a fuel gas, and in the production of ethylene and propylene. Changes in the composition of refined products resulting from governmental regulation, changes in feedstocks, products and economics, demand for heating fuel and for ethylene and propylene could adversely affect demand for normal butane.
- *Isobutane.* Isobutane is predominantly used in refineries to produce alkylates to enhance octane levels. Accordingly, any action that reduces demand for motor gasoline or demand for isobutane to produce alkylates for octane enhancement might reduce demand for isobutane.
- *Natural Gasoline.* Natural gasoline is used as a blending component for certain refined products and as a feedstock used in the production of ethylene and propylene. Changes in the mandated composition resulting from governmental regulation of motor gasoline and in demand for ethylene and propylene could adversely affect demand for natural gasoline.

NGLs and products produced from NGLs also compete with global markets. Any reduced demand for ethane, propane, normal butane, isobutane or natural gasoline in the markets the Partnership accesses for any of the reasons stated above could adversely affect demand for the services the Partnership provides as well as NGL prices, which would negatively impact its results of operations and financial condition.

Growing the Partnership's business by constructing new pipelines and processing facilities subjects it to construction risks, risks that natural gas or NGL supplies will not be available upon completion of the facilities and risks of construction delay and additional costs due to obtaining rights-of-way and complying with federal, state and local laws.

One of the ways the Partnership intends to grow its business is through the construction of additions to its existing gathering systems and construction of new pipelines and gathering and processing facilities. The construction of pipelines and gathering and processing and fractionation facilities requires the expenditure of significant amounts of capital, which may exceed its expectations. Generally, the Partnership may have only limited natural gas or NGL supplies committed to these facilities prior to their construction. Moreover, it may construct facilities to capture anticipated future growth in production in a region in which anticipated production growth does not materialize. The Partnership may also rely on estimates of proved reserves in its 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 its expected investment return, which could adversely affect the Partnership's results of operations and financial condition. In addition, the Partnership faces the risks of construction delay and additional costs due to obtaining rights-of-way and local permits and complying with federal or state laws and city ordinances, particularly as the Partnership expands its operations into more urban, populated areas such as the Barnett Shale.

If the Partnership does not make acquisitions on economically acceptable terms or efficiently and effectively integrate the acquired assets with its asset base, its future growth will be limited.

The Partnership's ability to grow depends, in part, on its ability to make acquisitions that result in an increase in cash generated from operations on a per unit basis. If the Partnership is unable to make accretive acquisitions either because it is (1) unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them, (2) unable to obtain financing for these acquisitions on economically acceptable terms or (3) outbid by competitors, then its future growth and its ability to increase distributions will be limited.

From time to time, the Partnership may evaluate and seek to acquire assets or businesses that it believes complement its existing business and related assets. The Partnership may acquire assets or businesses that it plans 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, especially if the assets acquired are in a new business segment or geographic area;
- the diversion of management's attention from other business concerns;
- the failure to realize expected volumes, revenues, profitability or growth;
- the failure to realize any expected synergies and cost savings;
- the coordination of geographically disparate organizations, systems and facilities;
- the assumption of unknown liabilities;
- the loss of customers or key employees from the acquired businesses;
- a significant increase in the Partnership's 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 the Partnership's operations and cash flows. If the Partnership consummates any future acquisition, its 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 the Partnership will consider in determining the application of these funds and other resources.

Additionally, the Partnership's ability to grow its asset base in the near future through acquisitions may be limited due to constrained capital markets.

The terms of the Partnership's credit facility and indenture may restrict its current and future operations, particularly its ability to respond to changes in business or to take certain actions.

The Partnership's credit agreement and the indenture governing its senior notes contain, and any future indebtedness the Partnership incurs will likely contain, a number of restrictive covenants that impose significant operating and financial restrictions, including restrictions on its ability to engage in acts that may be in its best long-term interest. These agreements include covenants that, among other things, restrict its ability to:

- incur or guarantee additional indebtedness or issue preferred stock;
- pay dividends on its equity securities or redeem, repurchase or retire its equity securities or subordinated indebtedness;
- make investments;
- create restrictions on the payment of dividends or other distributions by its subsidiaries;
- engage in transactions with its affiliates;
- sell assets, including equity securities of its subsidiaries;
- consolidate or merge;
- incur liens;
- prepay, redeem and repurchase certain debt;
- make certain acquisitions;
- transfer assets;
- enter into sale and lease back transactions;
- amend its partnership agreement;
- make certain capital expenditures; and
- change business activities it conducts.

In addition, the Partnership's credit facility requires it to satisfy and maintain specified financial ratios and other financial condition tests. Its ability to meet those financial ratios and tests can be affected by events beyond its control, and it cannot assure you that it will meet those ratios and tests.

A breach of any of these covenants could result in an event of default under the Partnership's credit facility and indenture. Upon the occurrence of such an event of default, all amounts outstanding under the applicable debt agreements could be declared to be immediately due and payable and all applicable commitments to extend further credit could be terminated. If the Partnership is unable to repay the accelerated debt under its senior secured credit facility, the lenders under its senior secured credit facility could proceed against the collateral granted to them to secure that indebtedness. The Partnership has pledged substantially all of its assets as collateral under its senior secured credit facility. If indebtedness under its senior secured credit facility or indentures is accelerated, it cannot assure you that it will have sufficient assets to repay the indebtedness. The operating and financial restrictions and covenants in these debt agreements and any future financing agreements may adversely affect its ability to finance future operations or capital needs or to engage in other business activities.

The Partnership does not own most of the land on which its pipelines and compression facilities are located, which could disrupt its operations.

The Partnership does not own most of the land on which its pipelines and compression facilities are located, and it is therefore subject to the possibility of more onerous terms and/or increased costs to retain necessary land use if it does not have valid rights-of-way or leases or if such rights-of-way or leases lapse or terminate. The Partnership sometimes obtains the rights to land owned by third parties and governmental agencies for a specific period of time. The Partnership's loss of these rights, through its inability to renew right-of-way contracts, leases or otherwise, could cause it to cease operations on the affected land, increase costs related to continuing operations elsewhere, and reduce its revenue.

The Partnership expects to encounter significant competition in any new geographic areas into which the Partnership seeks to expand and its ability to enter such markets may be limited.

If the Partnership expands its operations into new geographic areas, the Partnership expects to encounter significant competition for natural gas supplies and markets. Competitors in these new markets will include companies larger than the Partnership, which have both lower cost of capital and greater geographic coverage, as well as smaller companies, which have lower total cost structures. As a result, it may not be able to successfully develop acquired assets and markets located in new geographic areas and the Partnership's results of operations could be adversely affected.

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

The renewal or replacement of existing contracts with the Partnership's customers at rates sufficient to maintain current revenues and cash flows depends on a number of factors beyond its control, including competition from other pipelines, and the price of, and demand for, natural gas in the markets the Partnership serves. The inability of the Partnership's management to renew or replace its current contracts as they expire and to respond appropriately to changing market conditions could have a negative effect on its profitability.

In particular, the Partnership's ability to renew or replace its existing contracts with industrial end-users and utilities impacts its profitability. For the year ended December 31, 2011, approximately 49% of its sales of gas that was transported using its 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 the Partnership in the marketing of natural gas, the Partnership often competes in the end-user and utilities markets primarily on the basis of price.

The Partnership depends on certain key customers, and the loss of any of its key customers could adversely affect its financial results.

The Partnership derives a significant portion of its revenues from contracts with key customers. To the extent that these and other customers may reduce volumes of natural gas purchased or transported under existing contracts, the Partnership would be adversely affected unless it was able to make comparably profitable arrangements with other customers. Certain agreements with key customers provide for minimum volumes of natural gas or natural gas services that require the customer to transport, process or purchase until the expiration of the term of the applicable agreement, subject to certain force majeure provisions. Customers may default on their obligations to transport, process or purchase the minimum volumes of natural gas or natural gas services required under the applicable agreements.

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

Risks of nonpayment and nonperformance by the Partnership's customers are a major concern in its business. The Partnership is subject to risks of loss resulting from nonpayment or nonperformance by its customers and other counterparties, such as its lenders and hedging counterparties. Any increase in the nonpayment and nonperformance by its customers could adversely affect its results of operations and reduce its ability to make distributions to its unitholders.

Federal, state or local regulatory measures could adversely affect the Partnership's business.

The Partnership's natural gas gathering and processing activities generally are exempt from FERC regulation under the Natural Gas Act. 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 the Partnership's 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. The Partnership's 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. The Partnership cannot predict what effect, if any, such changes might have on its operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

The rates, terms and conditions of service under which the Partnership transports natural gas in its pipeline systems in interstate commerce are subject to FERC regulation under Section 311 of the Natural Gas Policy Act. Under these regulations, the Partnership is required to justify its rates for interstate transportation service on a cost-of-service basis, every three years. The Partnership's intrastate natural gas pipeline operations 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 its rates for Section 311 transportation service or intrastate transportation service should be lowered, its business could be adversely affected.

The Cajun-Sibon NGL pipeline is scheduled to be operational in the first half of 2013. The rates for service on that pipeline will be regulated by FERC under the Interstate Commerce Act, the Energy Policy Act of 1992 and regulations and orders promulgated thereunder. In 2012, the Partnership intends to request FERC's authorization of the initial rates to be charged for transportation service on the Cajun-Sibon NGL pipeline. FERC may not approve the proposed initial rates or may otherwise limit the revenues the Partnership may collect for transporting NGLs on the pipeline.

When the Cajun-Sibon NGL pipeline is operational, its rates may be subject to decrease and the Partnership may be required to pay refunds or reparations. The Interstate Commerce Act permits interested persons to challenge proposed new or changed rates and authorizes FERC to suspend the effectiveness of such rates for up to seven months and investigate such rates. If, upon completion of an investigation, FERC finds that the new or changed rate is unlawful, it is authorized to require the pipeline to refund revenues collected in excess of the just and reasonable rate during the term of the investigation. The just and reasonable rate used to calculate refunds cannot be lower than the last tariff rate approved as just and reasonable. FERC may also investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Upon an appropriate showing, a shipper may obtain reparations for charges in excess of a just and reasonable for a period of up to two years prior to the filing of a complaint.

FERC's primary ratemaking methodology for NGL pipelines is the annual indexing methodology, under which pipelines increase or decrease their rates in accordance with an index adjustment specified by FERC. Under FERC's regulations, an NGL pipeline can request a rate increase that exceeds the rate obtained through application of the indexing methodology by using a cost-of-service approach, but only after the pipeline establishes that a substantial divergence exists between the actual costs experienced by the pipeline and the rates resulting from application of the indexing methodology. If the Partnership is limited to the increases permitted under the indexing methodology, the Partnership may be unable to collect revenues sufficient to recover its cost of service.

Other state and local regulations also affect the Partnership's business. The Partnership is subject to some ratable take and common purchaser statutes in the states where it operates. 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 the Partnership's right as an owner of gathering facilities to decide with whom it contracts 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 it operates have adopted complaint-based or other limited economic regulation of natural gas gathering activities. States in which the Partnership operates that have adopted some form of complaint-based regulation, like 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 the Partnership conducts operations administer federal pipeline safety standards under the Natural Gas Pipeline Safety Act of 1968. These standards only apply to certain gathering lines based on the gathering line's operating pressure and proximity to people. Because of their pressure and location, substantial portions of its gathering facilities are not regulated under that statute. The gathering line exemptions, however, may be restricted in the future, and they do 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, including gathering lines.

Compliance with pipeline integrity and other pipeline safety regulations issued by the United States Department of Transportation or those issued by the TRRC 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. The Partnership's costs relating to compliance with the required testing under the TRRC regulations, adjusted to exclude costs associated with discontinued operations, were approximately at $1.3 million, $1.4 million, and $1.1 million for the years ended December 31, 2011, 2010, and 2009, respectively. The Partnership expects the costs for compliance with TRRC and DOT regulations to be approximately $2.0 million during 2012. If its pipelines fail to meet the safety standards mandated by the TRRC or the DOT regulations, then it may be required to repair or replace sections of such pipelines, the cost of which cannot be estimated at this time.

As the Partnership's operations continue to expand into and around urban, or more populated areas, such as the Barnett Shale, it may incur additional expenses to mitigate noise, odor and light that may be emitted in its operations, and expenses related to the appearance of its facilities. Municipal and other local or state regulations are imposing various obligations, including, among other things, regulating the location of its facilities, imposing limitations on the noise levels of its facilities and requiring certain other improvements that increase the cost of its facilities. The Partnership is also subject to claims by neighboring landowners for nuisance related to the construction and operation of its facilities, which could subject it to damages for declines in neighboring property values due to its construction and operation of facilities.

The Partnership's business involves hazardous substances and may be adversely affected by environmental regulation.

Many of the operations and activities of the Partnership's gathering systems, processing plants, fractionators and other facilities are subject to significant federal, state and local environmental laws and regulations. The obligations imposed by these laws and regulations include obligations related to air emissions and discharge of pollutants from its facilities and the cleanup of hazardous substances and other wastes that may have been released at properties currently or previously owned or operated by the Partnership or locations to which the Partnership has sent wastes for treatment or disposal. Various governmental authorities have the power to enforce compliance with these laws and 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 near the Partnership's facilities or upon or through which its gathering systems traverse, 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 for releases of contaminants or for personal injury or property damage.

There is inherent risk of the incurrence of significant environmental costs and liabilities in the Partnership's business due to its handling of natural gas and other petroleum substances, air emissions related to its 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 its compliance costs and the cost of any remediation that may become necessary. The Partnership may incur material environmental costs and liabilities. Furthermore, its insurance may not provide sufficient coverage in the event an environmental claim is made against it.

The Partnership's 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 laws or regulations, including, for example, legislation relating to the control of greenhouse gas emissions, or changes in existing environmental laws or regulations might adversely affect its 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 its profitability. Changes in laws or regulations could also limit its production or the operation of its assets or adversely affect its ability to comply with applicable legal requirements or the demand for natural gas, which could adversely affect its business and its profitability.

The Partnership's business involves many hazards and operational risks, some of which may not be fully covered by insurance.

The Partnership's operations are subject to the many hazards inherent in the gathering, compressing, processing and storage of natural gas and NGLs, 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 the Partnership's related operations. The Partnership is not fully insured against all risks incident to its business. In accordance with typical industry practice, the Partnership does not have any property insurance on any of its underground pipeline systems that would cover damage to the pipelines. The Partnership is not insured against all environmental accidents that might occur, other than those considered to be sudden and accidental. If a significant accident or event occurs that is not fully insured, it could adversely affect the Partnership's operations and financial condition.

The adoption of derivatives legislation by the United States Congress could have an adverse effect on the Partnership's ability to hedge risks associated with its business.

The United States Congress has adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as the Partnership, that participate in that market. The new legislation was signed into law by the President on July 21, 2010, and requires the Commodities Futures Trading Commission (the "CFTC") and the SEC to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. The CFTC has also promulgated regulations that set position limits for certain futures and option contracts in the major energy markets. The financial reform legislation may also require the Partnership to comply with margin requirements in connection with its derivative activities, although the application of those provisions to the Partnership is uncertain at this time. The CFTC has proposed regulations that may provide to the Partnership the certainty that it will not be required to comply with margin requirements, but the timing of the adoption of any such regulations, and their scope, are uncertain. If margin requirements and other trading structures apply to the Partnership, the new legislation and any new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks the Partnership encounters, and reduce its ability to monetize or restructure its existing derivative contracts. If the Partnership reduces its use of derivatives as a result of the legislation and regulations, its results of operations may become more volatile and its cash flows may be less predictable, which could adversely affect its ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. The Partnership's revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material, adverse effect on the Partnership's financial condition and results of operations.

Climate change legislation and regulatory initiatives could result in increased operating costs and reduced demand for the natural gas and NGL services the Partnership provides.

On December 15, 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases (“GHGs”) present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth’s atmosphere and other climatic changes. These findings allowed the EPA to proceed with the adoption and implementation of regulations restricting emissions of GHGs under existing provisions of the federal Clean Air Act. Accordingly, the EPA has adopted two sets of regulations under the Clean Air Act that would require a reduction in emissions of GHGs from motor vehicles and could trigger permit review for GHG emissions from certain stationary sources. Moreover, on October 30, 2009, the EPA published a “Mandatory Reporting of Greenhouse Gases” final rule that establishes a new comprehensive scheme requiring operators of stationary sources emitting more than established annual thresholds of carbon dioxide-equivalent GHGs to inventory and report their GHG emissions annually on a facility-by-facility basis, which was expanded by a rule promulgated on November 30, 2010 to include owners and operators of onshore oil and natural gas production, processing, transmission, storage and distribution facilities. Reporting emissions from such onshore activities is required on an annual basis beginning in 2012 for emissions occurring in 2011.

In addition, both houses of Congress have actively considered legislation to reduce emissions of GHGs, and almost half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring either major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and NGL fractionation plants, to acquire and surrender emission allowances with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved. The adoption of legislation or regulations imposing reporting or permitting obligations on, or limiting emissions of GHGs from, the Partnership’s equipment and operations could require the Partnership to incur additional costs to reduce emissions of GHGs associated with its operations, could adversely affect its performance of operations in the absence of any permits that may be required to regulate emission of greenhouse gases, or could adversely affect demand for the natural gas the Partnership gathers, processes or otherwise handles in connection with its services.

The Partnership typically does not obtain independent evaluations of natural gas reserves dedicated to its gathering pipeline systems; therefore, volumes of natural gas on its systems in the future could be less than it anticipates.

The Partnership typically does not obtain independent evaluations of natural gas reserves connected to its gathering systems due to the unwillingness of producers to provide reserve information as well as the cost of such evaluations. Accordingly, the Partnership does not have independent estimates of total reserves dedicated to its gathering systems or the anticipated life of such reserves. If the total reserves or estimated life of the reserves connected to its gathering systems is less than it anticipates and it is unable to secure additional sources of natural gas, then the volumes of natural gas transported on its gathering systems in the future could be less than anticipated. A decline in the volumes of natural gas on its systems could have a material adverse effect on its results of operations and financial condition.

The Partnership’s success depends on key members of its management, the loss or replacement of whom could disrupt its business operations.

The Partnership depends on the continued employment and performance of the officers of its general partner and key operational personnel. The 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, the Partnership's business operations could be materially adversely affected. The Partnership does not maintain any "key man" life insurance for any officers.

Increased regulation of hydraulic fracturing could result in reductions or delays in natural gas production by our customers, which could adversely impact our revenues.

A portion of the Partnership's customers' natural gas production is developed from unconventional sources, such as deep gas shales, that require hydraulic fracturing as part of the completion process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into the formation to stimulate gas production. Hydraulic fracturing activities are generally regulated by state oil and gas commissions. In recent years, however, there have been federal legislative and administrative agency initiatives that would subject the process to increased regulation at the federal level. Legislation to amend the Safe Drinking Water Act to repeal the exemption for hydraulic fracturing from definition of "underground injection" and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, were proposed in recent sessions of Congress. The U.S. Congress continues to consider legislation to amend the Safe Drinking Water Act. Scrutiny of hydraulic fracturing activities continues in other ways, with the EPA having commenced a multi-year study of the potential environmental impacts of hydraulic fracturing, the results of which are anticipated to be available in late 2012. Several states have also proposed or adopted legislative or regulatory requirements imposing disclosure obligation with respect to the composition of hydraulic fracturing . The Partnership cannot predict whether any additional legislation or regulations will be enacted and if so, what the provisions would be. If additional levels of regulation and permits were required through the adoption of new laws and regulations at the federal or state level, that could lead to delays, increased operating costs and process prohibitions that could reduce the volumes of natural gas that move through its gathering systems which would materially adversely affect its revenue and results of operations.

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 the Partnership's 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. The Partnership has 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 the Partnership's pipeline was built was purchased in fee. The Partnership's processing plants are located on land that the Partnership leases or owns in fee.

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

Item 3. *Legal Proceedings*

Our operations and those of the Partnership are subject to a variety of risks and disputes normally incident to our business. As a result, at any given time we or the Partnership may be a defendant in various legal proceedings and litigation arising in the ordinary course of business, including litigation on disputes related to contracts, property use or damage and personal injury. Additionally, as the Partnership continues to expand operations into more urban, populated areas, such as the Barnett Shale, it may see an increase in claims brought by area landowners, such as nuisance claims and other claims based on property rights. Except as otherwise set forth herein, we do not believe that any pending or threatened claim or dispute is material to our financial results on 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.

On June 7, 2010, Formosa Plastics Corporation, Texas, Formosa Plastics Corporation America, Formosa Utility Venture, Ltd., and Nan Ya Plastics Corporation, America filed a lawsuit against Crosstex Energy, Inc., Crosstex Energy, L.P., Crosstex Energy GP, L.P., Crosstex Energy GP, LLC, Crosstex Energy Services, L.P., and Crosstex Gulf Coast Marketing, Ltd. in the 24th Judicial District Court of Calhoun County, Texas, asserting claims for negligence, *res ipsa loquitor*, products liability and strict liability relating to the alleged receipt by the plaintiffs of natural gas liquids into their facilities from facilities operated by the Partnership. The amended petition alleges that the plaintiffs have incurred approximately $35.0 million in damages, including damage to equipment and lost profits. The Partnership has submitted the claim to its insurance carriers and intends to vigorously defend the lawsuit. The Partnership believes that any recovery would be within applicable policy limits. Although it is not possible to predict the ultimate outcome of this matter, the Partnership does not expect that an award in this matter will have a material adverse impact on its consolidated results of operations or financial condition.

At times, our gas-utility subsidiaries acquire pipeline easements and other property rights by exercising rights of eminent domain provided under state law. As a result, the Partnership (or its subsidiaries) is a party to a number of lawsuits under which a court will determine the value of pipeline easements or other property interests obtained by the Partnership's gas utility subsidiaries by condemnation. Damage awards in these suits should reflect the value of the property interest acquired and the diminution in the value of the remaining property owned by the landowner. However, some landowners have alleged unique damage theories to inflate their damage claims or assert valuation methodologies that could result in damage awards in excess of the amounts anticipated. Although it is not possible to predict the ultimate outcomes of these matters, the Partnership does not expect that awards in these matters will have a material adverse impact on its consolidated results of operations or financial condition.

The Partnership (or its subsidiaries) is defending a number of lawsuits filed by owners of property located near processing facilities or compression facilities constructed by the Partnership as part of its systems. The suits generally allege that the facilities create a private nuisance and have damaged the value of surrounding property. Claims of this nature have arisen as a result of the industrial development of natural gas gathering, processing and treating facilities in urban and occupied rural areas. Although it is not possible to predict the ultimate outcomes of these matters, the Partnership does not expect that awards in these matters will have a material adverse impact on its consolidated results of operations or financial condition.

Item 4. *Mine Safety Disclosures*

None.

PART II

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

Our common stock is listed on The NASDAQ Global Select Market under the symbol "XTXI". Our common stock began trading on January 12, 2004. On February 14, 2012, the closing market price for our common stock was $13.57 per share and there were approximately 11,572 record holders and beneficial owners (held in street name) of the shares of our common stock. For equity compensation plan information, see discussion under "Item 12 Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters—Equity Compensation Plan Information."

The following table shows (i) the high and low closing sales prices per share, as reported by The NASDAQ Global Select Market, and (ii) the amount of our quarterly dividends for the periods indicated.

	Common Stock Price Range		Cash Dividends
	High	**Low**	**Declared Per Share**
2011:			
Quarter Ended December 31	$14.70	$10.92	$0.11
Quarter Ended September 30	15.14	8.62	0.10
Quarter Ended June 30	11.90	9.02	0.10
Quarter Ended March 31	10.52	8.41	0.09
2010:			
Quarter Ended December 31	$ 9.78	$ 7.82	0.08
Quarter Ended September 30	8.45	5.65	0.07
Quarter Ended June 30	9.65	6.02	—
Quarter Ended March 31	9.68	6.37	—

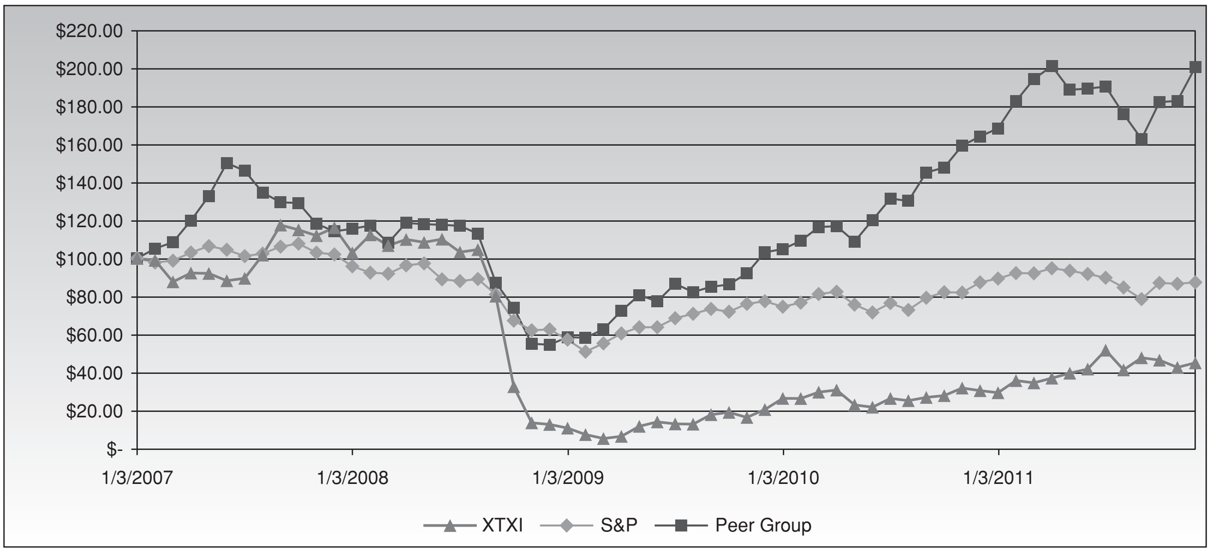
We intend to pay dividends to our stockholders, on a quarterly basis, equal to the cash we receive if any, from distributions from the Partnership, less reserves for expenses, future dividends and other uses of cash, including:

- federal income taxes, which we are required to pay because we are taxed as a corporation;
- the expenses of being a public company;
- other general and administrative expenses;
- capital contributions to the Partnership upon the issuance by it of additional partnership securities in order to maintain the general partner's 2.0% general partner interest; and
- reserves our board of directors believes prudent to maintain.

The determination of the amount of cash dividends, including the quarterly dividend referred to above, if any, to be declared and paid will depend upon our financial condition, results of operations, cash flow, the level of our capital expenditures, future business prospects and any other matters that our board of directors deems relevant. The Company intends to pay dividends to stockholders and is dependent on receiving a cash distribution from the Partnership. During 2011, the Partnership paid quarterly distributions to its common unitsholders in May, August, and November of $0.29, $0.31, and $0.31 related to the first, second, and third quarters of 2011, respectively. The Partnership paid a quarterly distribution of $0.32 in February 2012 related to the fourth quarter of 2011. Our share of the distributions with respect to our limited and general partner interests in the Partnership totaled $22.5 million for the year ended December 31, 2011.

Performance Graph

The following graph sets forth the cumulative total stockholder return for our common stock, the Standard & Poor's 500 Stock Index, and a peer group of publicly traded partners of publicly traded limited partnerships in the Midstream natural gas, natural gas liquids, propane, and pipeline industries from January 1, 2007, through December 31, 2011. The chart assumes that $100 was invested on January 1, 2007, with dividends reinvested. The peer group includes Atlas Energy, L.P., Alliance Holdings GP, L.P., Energy Transfer Equity, L.P., Nustar GP Holdings, LLC and Targa Resources, Inc. (Targa Resources, Inc.'s initial public offering was in January 2010, and it has been assumed that it performed in accordance with the peer group average prior to such date).



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

The following table sets forth selected historical financial and operating data of Crosstex Energy, Inc as of and for the dates and periods indicated. The selected historical financial data are derived from the audited consolidated financial statements of Crosstex Energy, L.P. and should be read together with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

	Crosstex Energy, Inc.				
	Years Ended December 31,				
	2011	2010	2009	2008	2007
	(In thousands, except per share data)				
Statement of Operations Data:					
Revenues:					
Midstream	$2,013,942	$1,792,676	$1,583,551	$3,558,213	$2,635,329
Operating costs and expenses:					
Purchased gas and NGLs	1,638,777	1,454,376	1,272,329	3,250,427	2,375,503
Operating expenses	111,778	105,060	110,394	125,762	91,236
General and administrative	55,516	51,172	62,491	72,377	62,270
(Gain) loss on derivatives	7,776	9,100	(2,994)	(8,619)	(4,147)
(Gain) loss on sale of property	264	(13,881)	(666)	(947)	(1,024)
Impairments	—	1,311	2,894	30,177	—
Depreciation and amortization	125,358	111,625	119,162	107,652	83,361
Total operating costs and expenses	1,939,469	1,718,763	1,563,610	3,576,829	2,607,199
Operating income (loss)	74,473	73,913	19,941	(18,616)	28,130
Other income (expense):					
Interest expense, net	(79,227)	(87,028)	(95,078)	(74,861)	(47,649)
Loss on extinguishment of debt	—	(14,713)	(4,669)	—	—
Other income	707	294	1,449	27,898	538
Total other expense	(78,520)	(101,447)	(98,298)	(46,963)	(47,111)
Loss from continuing operations before income taxes and gain on issuance of Partnership units	(4,047)	(27,534)	(78,357)	(65,579)	(18,981)
Income tax benefit (provision)	2,768	6,021	6,020	1,375	(6,319)
Gain on issuance of Partnership units(1)	—	—	—	14,748	7,461
Loss from continuing operations before cumulative effect of change in accounting principle, net of tax	(1,279)	(21,513)	(72,337)	(49,456)	(17,839)
Discontinued Operations:					
Income (loss) from discontinued operations, net of tax	—	—	(1,519)	21,466	26,817
Gain from sale of discontinued operations, net of tax	—	—	159,961	42,753	—
Discontinued operations, net of tax	—	—	158,442	64,219	26,817
Net income (loss)	(1,279)	(21,513)	86,105	14,763	8,978
Less: Interest of non-controlling partners in the Partnership's net income (loss):					
Interest of non-controlling partners in the Partnership's continuing operations	4,728	(9,862)	(48,069)	(55,704)	(22,331)
Interest of non-controlling partners in the Partnership's discontinued operations	—	—	(1,137)	15,454	19,133
Interest of non-controlling partners in the Partnership's gain on sale of discountinued operations	—	—	119,669	30,780	—
Total interest of non-controlling partner in the partnership's net income (loss)	4,728	$ (9,862)	70,463	(9,470)	(3,198)
Net income (loss) attributable to Crosstex Energy, Inc.	$ (6,007)	$ (11,651)	$ 15,642	$ 24,233	$ 12,176
Net income (loss) from continuing operations per common share:					
Basic	$ (0.12)	$ (0.24)	$ (0.52)	$ 0.13	$ 0.10
Diluted	$ (0.12)	$ (0.24)	$ (0.52)	$ 0.13	$ 0.09
Dividends per share—common(2)	$ 0.37	$ 0.07	$ 0.09	$ 1.32	$ 0.91
Balance Sheet Data (end of period):					
Working capital deficit	$ (16,802)	$ (12,781)	$ (41,791)	$ (20,431)	$ (39,330)
Property and equipment, net	1,242,890	1,216,166	1,280,233	1,528,490	1,426,546
Total assets	1,962,616	1,991,103	2,080,233	2,546,743	2,602,829
Long-term and current maturities of debt	798,409	718,570	873,702	1,263,706	1,223,118
Capital lease obligations (including current maturities)	28,367	31,327	23,799	27,896	3,988
Interest of non-controlling partners in the Partnership	666,827	717,063	587,624	522,961	489,034
Stockholders' equity	829,247	901,478	815,910	738,390	246,366
Cash Flow Data:					
Net cash flow provided by (used in)(3):					
Operating activities	$ 141,293	$ 84,790	$ 78,850	$ 170,154	$ 112,578
Investing activities	(132,094)	14,638	379,874	(186,768)	(411,382)
Financing activities	(1,636)	(87,351)	(461,980)	22,720	296,022
Non-GAAP Financial Measures:					
Gross operating margin(4)	$ 375,165	$ 338,300	$ 311,222	$ 307,786	$ 259,826
Partnership's adjusted EBITDA from continuing operations(5)	$ 214,028	$ 186,880	$ 158,682	$ 163,394	$ 126,944
Operating Data:					
Pipeline throughput (MMBtu/d)	2,037,000	1,971,000	2,040,000	2,002,000	1,555,000
Natural gas processed (MMBtu/d)	1,325,000	1,366,000	1,235,000	1,608,000	1,835,000
Commercial services (MMBtu/d)	92,000	99,000	75,000	85,000	94,000
NGL Fractionation (Gals/d)	1,109,000	922,000	686,000	956,000	980,000

(1) We recognized gains of $14.7 million in 2008 and $7.5 million in 2007 as a result of the Partnership issuing additional units in public offerings at prices per unit greater than our equivalent carrying value.

(2) Dividend Paid.

(3) Cash flow data includes cash flows from discontinued operations.

(4) Gross operating margin is defined as revenue less related cost of purchased gas and NGLs.

(5) Partnership's adjusted EBITDA from continuing operations is defined as net income plus interest expense, provision for income taxes and depreciation and amortization expense, impairments, stock-based compensation, loss on extinguishment of debt, (gain) loss on noncash derivatives, transaction cost associated with successful transactions, minority interest; certain severance and exit expenses; and accrued legal judgment under appeal; less (income) loss from discontinued operations and gain on sale of assets related to discontinued operations.

Non-GAAP Financial Measures

We include the following non-GAAP financial measures: the Partnership's adjusted EBITDA from continuing operations and gross operating margin. We provide reconciliations of these non-GAAP financial measures to their most directly comparable financial measures as calculated and presented in accordance with generally accepted accounting principles, or GAAP.

We define adjusted EBITDA from continuing operations as net income plus interest expense, provision for income taxes and depreciation and amortization expense, impairments, stock-based compensation, loss on extinguishment of debt, (gain) loss on noncash derivatives, transaction costs associated with successful transactions, minority interest; certain severance and exit expenses; and accrued legal judgment under appeal; less (income) loss from discontinued operations and gain on sale of assets related to discontinued operations. The Partnership's adjusted EBITDA from continuing operations is used as a supplemental performance measure by its management and by external users of its financial statements such as investors, commercial banks, research analysts and others, to assess:

- financial performance of the Partnership's assets without regard to financing methods, capital structure or historical cost basis;
- the ability of the Partnership's assets to generate cash sufficient to pay interest costs, support its indebtedness and make cash distributions to its unitholders and the general partner;
- the Partnership's operating performance and return on capital as compared to those of other companies in the midstream energy sector, without regard to financing methods or capital structure; and
- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

The Partnership's adjusted EBITDA from continuing operations is one of the critical inputs into the financial covenants within the Partnership's credit facility. The rates the Partnership pays for borrowings under its credit facility are determined by the ratio of its debt to the Partnership's adjusted EBITDA. The calculation of these ratios allows for further adjustments to the Partnership'sadjusted EBITDA for recent acquisitions and dispositions.

The Partnership's adjusted EBITDA from continuing operations should not be considered an alternative to, or more meaningful than, net income, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP. The Partnership's adjusted EBITDA from continuing operations may not be comparable to similarly titled measures of other companies because other entities may not calculate adjusted EBITDA from continuing operations in the same manner.

The Partnership's adjusted EBITDA from continuing operations does not include interest expense, income taxes or depreciation and amortization expense. Because the Partnership has borrowed money to finance its operations, interest expense is a necessary element of its costs and its ability to generate cash available for distribution. Because the Partnership uses capital assets, depreciation and amortization are also necessary elements of its costs. Therefore, any measures that exclude these elements have material limitations. To compensate for these limitations, we believe that it is important to consider both net earnings determined under GAAP, as well as the Partnership's adjusted EBITDA, to evaluate the Partnership's overall performance.

The following table provides a reconciliation of the Partnership's adjusted EBITDA to net income (loss):

	Years Ended December 31,				
	2011	2010	2009	2008	2007
	(In thousands)				
Net income (loss)	$ (6,007)	$ (11,651)	$ 15,642	$ 24,233	$ 12,176
Interest expense	79,227	87,028	95,078	74,861	47,649
Depreciation and amortization	125,358	111,625	119,162	107,652	83,361
Impairment	—	1,311	2,894	30,177	—
Loss on extinguishment of debt	—	14,713	4,669	—	—
(Gain) loss on sale of property	264	(13,881)	(666)	(947)	(1,024)
Stock-based compensation	7,556	9,569	8,854	11,279	12,259
(Income) loss from discontinued opertations, net of tax	—	—	1,519	(21,466)	(26,817)
Gain on sale of discontinued operations, net of tax	—	—	(159,961)	(42,753)	—
Gain on issuance of Partnership units	—	—	—	(14,748)	(7,461)
Minority interest	4,728	(9,862)	70,463	(9,470)	(3,198)
Taxes	(2,768)	(6,021)	(6,020)	(1,375)	6,319
Other(a)	5,670	4,049	7,048	5,951	3,680
Partnership's adjusted EBITDA from continuing operations	$214,028	$186,880	$ 158,682	$163,394	$126,944

(a) Includes the Partnership's financial derivatives marked-to-market, transaction cost associated with successful transactions, accrued expense of a legal judgment under appeal, the Partnership's severance and exit expenses (as allowed for adjustment under the Partnership's credit facility) and CEI's direct general and administrative expenses and other income are not included in the Partnership's adjusted EBTIDA.

We define gross operating margin as revenues minus cost of purchased gas and NGLs. We present gross operating margin by segment in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations." We disclose gross operating margin in addition to total revenue because it is the primary performance measure used by our management. We believe gross operating margin is an important measure because the Partnership's business is generally to purchase and resell natural gas for a margin or to gather, process, transport or market natural gas and NGLs for a fee. Operation and maintenance expense is a separate measure used by management to evaluate operating performance of field operations. Direct labor and supervision, property insurance, property taxes, repair and maintenance, utilities and contract services comprise the most significant portion of the Partnership's operation and maintenance expenses. These expenses are largely independent of the volumes the Partnership transports or processes and fluctuates depending on the activities performed during a specific period. We do not deduct operation and maintenance expenses from total revenue in calculating gross operating margin because we separately evaluate commodity volume and price changes in these margin amounts. As an indicator of our operating performance, gross operating margin should not be considered an alternative to, or more meaningful than, net income as determined in accordance with GAAP. Our gross operating margin may not be comparable to similarly titled measures of other companies because other entities may not calculate these amounts in the same manner.

The following table provides a reconciliation of gross operating margin to operating income (in thousands):

	Years Ended December 31,				
	2011	2010	2009	2008	2007
Total gross operating margin	$ 375,165	$ 338,300	$ 311,222	$ 307,786	$259,826
Add (deduct):					
Operating expenses	(111,778)	(105,060)	(110,394)	(125,762)	(91,236)
General and administrative expenses	(55,516)	(51,172)	(62,491)	(72,377)	(62,270)
Gain (loss) on sale of property	(264)	13,881	666	947	1,024
Gain (loss) on derivatives	(7,776)	(9,100)	2,994	8,619	4,147
Depreciation, amortization and impairments	(125,358)	(112,936)	(122,056)	(137,829)	(83,361)
Operating income	$ 74,473	$ 73,913	$ 19,941	$ (18,616)	$ 28,130

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

Crosstex Energy, Inc. is a Delaware corporation formed on April 28, 2000 to engage in the gathering, transmission, processing and marketing of natural gas and NGLs through its subsidiaries. On July 12, 2002, we formed Crosstex Energy, L.P., a Delaware limited partnership, to acquire indirectly substantially all of the assets, liabilities and operations of its predecessor, Crosstex Energy Services, Ltd. Our assets consist almost exclusively of partnership interests in Crosstex Energy, L.P., a publicly traded limited partnership engaged in the gathering, transmission, processing and marketing of natural gas and NGLs. These partnership interests consist of (i) 16,414,830 common units, representing approximately 25.0% of the limited partner interests in Crosstex Energy, L.P. as of December 31, 2011 and (ii) 100% ownership interest in Crosstex Energy GP, LLC, the general partner of Crosstex Energy, L.P., which owns a 2.0% general partner interest and all of the incentive distribution rights in Crosstex Energy, L.P.

Our cash flows consist almost exclusively of distributions from the Partnership on the partnership interests we own. The Partnership is required by its partnership agreement to distribute all its cash on hand at the end of each quarter, less reserves established by its general partner in its sole discretion to provide for the proper conduct of the Partnership's business or to provide for future distributions.

The incentive distribution rights entitle us to receive an increasing percentage of cash distributed by the Partnership as certain target distribution levels are reached. Specifically, they entitle us to receive 13.0% of all cash distributed in a quarter after each unit has received $0.25 for that quarter, 23.0% of all cash distributed after each unit has received $0.3125 for that quarter, and 48.0% of all cash distributed after each unit has received $0.375 for that quarter.

During 2011, the Partnership paid quarterly distributions to it common unitsholders in May, August, and November of $0.29, $0.31, and $0.31 related to the first, second, and third quarters of 2011, respectively. The Partnership paid a quarterly distribution of $0.32 in February 2012 related to the fourth quarter of 2011. Our share of the distributions with respect to our limited and general partner interests in the Partnership totaled $22.5 million for the year end December 31, 2011.

Since we control the general partner interest in the Partnership, we reflect our ownership interest in the Partnership on a consolidated basis, which means that our financial results are combined with the Partnership's financial results and the results of our other subsidiaries. The interest owned by non-controlling partners' share of income is reflected separately in our results of operations. We have no separate operating activities apart from those conducted by the Partnership, and our cash flows consist almost exclusively of distributions from the Partnership on the partnership interests we own. Our consolidated results of operations are derived from the results of operations of the Partnership and also include our gains on the issuance of units in the Partnership, deferred taxes, interest of non-controlling partners in the Partnership's net income, interest income (expense) and general and administrative expenses not reflected in the Partnership's results of operation. Accordingly, the discussion of our financial position and results of operations in this "Management's Discussion and Analysis of Financial Condition and Results of Operations" primarily reflects the operating activities and results of operations of the Partnership.

The Partnership's primary focus is on the gathering, processing, transmission and marketing of NGLs which it manages in regional reporting segments of midstream activity. The Partnership's geographic focus is in the North Texas Barnett Shale (NTX) and in Louisiana which has two reportable business segments (the LIG system and the south Louisiana processing and NGL assets, or PNGL). The Partnership manages its operations by focusing on gross operating margin because its business is generally to purchase and resell natural gas for a margin, or to gather, process, transport or market natural gas and NGLs for a fee. We define gross operating margin as operating revenue minus cost of purchased gas and NGLs.

The Partnership's gross operating margins are determined primarily by the volumes of natural gas gathered, transported, purchased and sold through its pipeline systems, processed at its processing facilities, and the volumes of NGLs handled at its fractionation facilities. The Partnership generates revenues from four primary sources:

- purchasing and reselling or transporting natural gas on the pipeline systems it owns;
- processing natural gas at its processing plants;
- fractionating and marketing the recovered NGLs; and
- providing compression services.

The Partnership generally gathers or transports gas owned by others through its facilities for a fee, or it buys natural gas from a producer, plant or shipper at either a fixed discount to a market index or a percentage of the market index, then transports and resells the natural gas at the market index. The Partnership attempts to execute all purchases and sales substantially concurrently, or it enters into a future delivery obligation, thereby establishing the basis for the margin it will receive for each natural gas transaction. The Partnership's gathering and transportation margins related to a percentage of the index price can be adversely affected by declines in the price of natural gas. The Partnership is also party to certain long-term gas sales commitments that it satisfies through supplies purchased under long-term gas purchase agreements. When the Partnership enters into those arrangements, its sales obligations generally match its purchase obligations. However, over time the supplies that it has under contract may decline due to reduced drilling or other causes and the Partnership may be required to satisfy the sales obligations by buying additional gas at prices that may exceed the prices received under the sales commitments. In the Partnership's purchase/sale transactions, the resale price is generally based on the same index at which the gas was purchased. However, on occasion the Partnership has entered into certain purchase/sale transactions in which the purchase price is based on a production-area index and the sales price is based on a market-area index, and it captures the difference in the indices (also referred to as basis spread), less the transportation expenses from the two areas, as margin. Changes in the basis spread can increase or decrease the margins.

One contract (the "Delivery Contract") has a term to 2019 that obligates the Partnership to supply approximately 150,000 MMBtu/d of gas. At the time that the Partnership entered into the Delivery Contract in 2008 it had dedicated supply sources in the Barnett Shale that exceeded the delivery obligations under the Delivery Contract. The Partnership's agreements with these suppliers generally provided that the purchase price for the gas was equal to a portion of its sales price for such gas less certain fees and costs. Accordingly, the Partnership was initially able to generate a positive margin under the Delivery Contract. However, since entering into the Delivery Contract, there has been both (1) a reduction in the gas available under the supply contracts and (2) the discovery of other shale reserves, most notably the Haynesville and the Marcellus Shales, which has increased the supplies available to East Coast markets and reduced the basis spread between north Texas-area production and the market indices used in the Delivery Contract. Due to these factors, the Partnership has had to purchase a portion of the gas to fulfill its obligations under the Delivery Contract at market prices, resulting in negative margins under the Delivery Contract.

The Partnership has recorded a loss of approximately $13.3 million during the year ended December 31, 2011 on the Delivery Contract. The Partnership expects that it will record a loss of approximately $13.0 million to $17.0 million on the Delivery Contract for the year ending December 31, 2012. This estimate is based on forward prices, basis spreads and other market assumptions as of year end 2011. These assumptions are subject to change if market conditions change during 2012, and actual results under the Delivery Contract in 2012 could be substantially different from year end 2011 estimates, which may result in a greater loss than currently estimated.

The Partnership also realizes gross operating margins from its processing services primarily through three different contract arrangements: processing margins (margin), percentage of liquids (POL) or fixed-fee based. Under margin contract arrangements the Partnership's margins are higher during periods of high liquid prices relative to natural gas prices. Gross operating margin results under POL contracts are impacted only by the value of the liquids produced with margins higher during periods of relatively high liquids prices. Under fixed-fee based contracts the Partnership's margins are driven by throughput volume. See "—Commodity Price Risk."

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, property insurance, ad valorem taxes, repair and maintenance expenses, measurement and utilities. These costs are normally fairly stable across broad volume ranges, and therefore do not normally decrease or increase significantly in the short term with decreases or increases in the volume of gas moved through the asset.

Business Strategy

The Partnership's business strategy consists of three overarching objectives which are to maximize earnings and growth of its existing businesses, to enhance the scale and diversification of its assets and to continue its focus on operational excellence. The Partnership believes it was successful in executing its business strategy during 2011, and it will continue to pursue these objectives in 2012.

- *Maximize earnings and growth of existing businesses.* The Partnership intends to leverage its franchise position, infrastructure and customer relationships by expanding existing systems to meet new or increased demand for its gathering, transmission, processing and marketing services.

- *Enhance scale and diversification of our assets.* The Partnership looks to grow and diversify by acquiring and/or building assets in new areas to serve as a platform for growth with a focus on areas with emerging shale plays and by expanding its NGL and crude oil infrastructure to provide services in new regions.

- *Continue to focus on operational excellence.* The Partnership continues to operate its existing asset base to maximize cost efficiencies, provide flexibility for its customers and provide reliable capacity for its customers. The Partnership will continue to focus on safety, environmental integrity, innovation and customer service.

Impact of Federal Income Taxes

We are a corporation for federal income tax purposes. As such, we are subject to federal income tax on our taxable income at a maximum rate of 35% under current law and are also subject to state income tax. While we have historically been allocated losses from our investment in the Partnership's units, we expect that in the future we will be allocated taxable income as the level of tax depreciation and amortization deductions allocated to us from the Partnership diminishes relative to the income allocated to us from the Partnership's operations.

As of December 31, 2011 we have a net operating loss carry forward of $120 million for federal tax purposes. We believe it is more likely than not that we will generate sufficient taxable income from our future operations to utilize these net operating loss carry forwards before they expire. Once these net operating loss carry forwards are fully utilized, we will be subject to federal income tax on our taxable income at a maximum rate of 35% under current law.

Our use of this net operating loss carry forward will be limited if there is an "ownership change" in our common stock (generally, cumulative stock ownership changes in our common stock exceeding 50% during a three year period, as determined under Section 382 of the Internal Revenue Code).

Commodity Price Risk

The Partnership's business is subject to significant risks due to fluctuations in commodity prices. Its exposure to these risks is primarily in the gas processing component of its business. For the year ended December 31, 2011, approximately 10.7% of the Partnership's processed gas arrangements, based on gross operating margin, was processed under percent of liquids (POL) contracts. A significant volume of inlet gas at the Partnership's south Louisiana and north Texas processing plants is settled under POL agreements. Under these contracts the Partnership receives a fee in the form of a percentage of the liquids recovered and the producer bears all the costs of the natural gas volumes lost ("shrink"). Accordingly, the Partnership's revenues under these contracts are directly impacted by the market price of NGLs.

The Partnership also realizes processing gross margins under processing margin (margin) contracts and spot purchases. For the year ended December 31, 2011, approximately 19.3% of the Partnership's processed gas arrangements, based on gross operating margin, was processed under margin contracts and spot purchases. The Partnership has a number of margin contracts on the Plaquemine, Gibson, Eunice, Bluewater, and Pelican processing plants. Under this type of contract, the Partnership pays the producer for the full amount of inlet gas to the plant and makes 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 shrink and the cost of fuel used in processing. The shrink and fuel losses are referred to as plant thermal reduction or PTR. The Partnership's margins from these contracts can be negative during periods of high natural gas prices relative to liquids prices.

The Partnership is also indirectly exposed to commodity prices due to the negative impacts on production and the development of production of natural gas and NGLs connected to or near the assets and on its margins for transportation between certain market centers. Low prices for these products will reduce the demand for the Partnership's services and volumes on its systems.

In the past, the prices of natural gas and NGLs have been extremely volatile and the Partnership expects this volatility to continue. For example, prices of natural gas in 2011 were below the market price realized throughout most of 2010 while prices for oil and NGLs were higher than 2010 market prices. Crude oil prices (based on the New York Mercantile Exchange (the "NYMEX") futures daily close prices for the prompt month) in 2011 ranged from a low of $75.67 per Bbl in October 2011 to a high of $113.93 per Bbl in April 2011. Weighted average NGL prices in 2011 (based on the Oil Price Information Service (OPIS) Napoleonville daily average spot liquids prices) ranged from a low of $0.99 per gallon in February 2011 to a high of $1.35 per gallon in May 2011. Natural gas prices (based on Gas Daily Henry Hub closing prices) during 2011 ranged from a high of $4.92 per MMBtu in June 2011 to a low of $2.79 per MMBtu in November 2011.

Changes in commodity prices may also indirectly impact the Partnership's profitability by influencing drilling activity and well operations, and thus the volume of gas the Partnership gathers and processes. The volatility in commodity prices may cause the Partnership's gross operating margin and cash flows to vary widely from period to period. Partnership hedging strategies may not be sufficient to offset price volatility risk and, in any event, do not cover all of the Partnership's throughput volumes. For a discussion of the Partnership's risk management activities, please read "Item 7A. Quantitative and Qualitative Disclosures about Market Risk."

Results of Operations

Set forth in the table below is certain financial and operating data for the periods indicated, which excludes financial and operating data deemed discontinued operations. The Partnership manages its operations by focusing on gross operating margin which the Partnership defines as operating revenue minus cost of purchased gas and NGLs as reflected in the table below.

	Years Ended December 31,		
	2011	2010	2009
	(Dollars in millions)		
LIG Segment			
Revenues	$ 939.3	$ 963.0	$ 893.8
Purchased gas and NGLs	(809.5)	(845.6)	(793.0)
Total gross operating margin	$ 129.8	$ 117.4	$ 100.8
NTX Segment			
Revenues	$ 432.6	$ 399.5	$ 509.4
Purchased gas and NGLs	(262.7)	(240.1)	(352.8)
Total gross operating margin	$ 169.9	$ 159.4	$ 156.6
PNGL Segment			
Revenues	$ 910.9	$ 602.6	$ 297.9
Purchased gas and NGLs	(835.4)	(541.1)	(250.1)
Total gross operating margin	$ 75.5	$ 61.5	$ 47.8
Corporate			
Revenues	$ (268.9)	$ (172.4)	$ (117.6)
Purchased gas and NGLs	268.9	172.4	123.6
Total gross operating margin	$ —	$ —	$ 6.0
Total			
Revenues	$ 2,013.9	$ 1,792.7	$ 1,583.5
Purchased gas and NGLs	(1,638.7)	(1,454.4)	(1,272.3)
Total gross operating margin	$ 375.2	$ 338.3	$ 311.2
Midstream Volumes:			
LIG			
Gathering and Transportation (MMBtu/d)	912,000	902,000	900,000
Processing (MMBtu/d)	247,000	283,000	269,000
NTX			
Gathering and Transportation (MMBtu/d)	1,125,000	1,069,000	1,111,000
Processing (MMBtu/d)	249,000	209,000	219,000
PNGL			
Processing (MMBtu/d)	829,000	874,000	747,000
NGL Fractionation (Gals/d)	1,109,000	922,000	686,000
Commercial Services (MMBtu/d)	92,000	69,000	75,000
Corporate			
Gathering and Transportation (MMBtu/d)	—	—	29,000

Year ended December 31, 2011 Compared to Year ended December 31, 2010

Gross Operating Margin. Gross operating margin was $375.2 million for the year ended December 31, 2011 compared to $338.3 million for the year ended December 31, 2010, an increase of $36.9 million, or 10.9%. The increase was due to increased throughput on the Partnership's gathering and transmission systems, as well as favorable NGL markets throughout the year. The following provides additional details regarding this change in gross operating margin:

- The LIG segment contributed gross operating margin growth of $12.4 million for the year ended December 31, 2011 compared to the year ended December 31, 2010. The continued strength of the processing environment contributed to a gross operating margin increase of $16.6 million. The Gibson and Plaquemine plants were the primary contributors to this gain with gross operating margin increases of $6.5 million and $3.5 million, respectively. Other processing activity contributed an additional gross operating margin increase of $6.6 million. The processing gains were partially offset by a decrease in gross operating margin of $4.2 million on the gathering and transportation assets. Gross operating margins on the Partnership's gathering and transportation assets decreased due to lower margins realized under new contracts and due to the expiration of certain contracts in 2011.

- The NTX segment had a gross operating margin increase of $10.5 million for the year ended December 31, 2011 compared to the year ended December 31, 2010. An increase in throughput volume primarily from the two expansion projects which commenced operations in March 2011 was the main contributor to a gross operating margin increase of $11.4 million on the gathering and transmission assets. The processing plants also had a gross operating margin increase of $3.9 million for the comparable periods due to increased supply and the favorable processing environment. These increases were partially offset by an increase in losses of $4.9 million on the Delivery Contract discussed more fully under "Overview".

- The favorable processing and NGL marketing environment contributed to a $14.0 million increase in gross operating margin for the PNGL segment for the year ended December 31, 2011 compared to the year ended December 31, 2010. The PNGL processing plants contributed a gross operating margin increase of $9.9 million. NGL fractionation and marketing activity generated a gross operating margin increase of $4.9 million due to the improved marketing environment and volume increases. The Sabine Pass plant had a gross operating margin decline of $0.9 million due to a decrease in volumes from the offshore pipelines that supply the plant.

Operating Expenses. Operating expenses were $111.8 million for the year ended December 31, 2011 compared to $105.1 million for the year ended December 31, 2010, an increase of $6.7 million, or 6.4%. The increase is primarily the result of the following:

- the Partnership's labor and benefits expense increased by $4.4 million related to an increase in accrued bonuses and employee headcount for activity related to project expansion in the north Texas segment and technical services;

- the Partnership experienced an increase of $0.5 million in bulk chemicals, supplies and service fees related to its project expansions;

- other costs increased by $2.0 million for an accrued legal judgment under appeal;

- the Partnership's electric utility costs increased $1.0 million due to an increase in operations at the Eunice processing plant and other north Texas project expansions; and

- the Partnership's operating costs decreased by $1.2 million primarily related to periodic testing incurred in 2010.

General and Administrative Expenses. General and administrative expenses were $55.5 million for the year ended December 31, 2011 compared to $51.2 million for the year ended December 31, 2010, an increase of $4.3 million, or 8.4%. The increase is primarily a result of the following:

- the Partnership's labor and benefits expense increased by $3.2 million primarily related to an increase in accrued bonuses and an increase in employee headcount; and

- the Partnership increased its bad debt expense by $1.0 million in 2011 due to uncollectible gathering fees related to a particular customer.

Gain/Loss on Sale of Property. Loss on sale of property was $0.3 million for the year ended December 31, 2011 compared to a gain of $13.9 million for the year ended December 31, 2010. The loss on sale of property for the year ended December 31, 2011 was primarily related to the sale of a minor section of pipeline in Louisiana in September 2011. The gain on sale of property for the year ended December 31, 2010 was related to the sale of the Partnership's east Texas assets in January 2010.

Gain/Loss on Derivatives. Loss on derivatives was $7.8 million for the year ended December 31, 2011 compared to a loss of $9.1 million for the year ended December 31, 2010. The derivative transaction types contributing to the net (gain) loss are as follows (in millions):

	Years Ended December 31,			
	2011		2010	
(Gain) Loss on Derivatives:	**Total**	**Realized**	**Total**	**Realized**
Basis swaps	$ 1.4	$1.3	$5.6	$2.3
Processing margin hedges	6.6	5.7	3.5	5.5
Other	(0.2)	—	—	0.1
Net loss on derivatives	$ 7.8	$7.0	$9.1	$7.9

Impairments. During 2010, impairments totaling $1.3 million were taken on excess pipe that was ultimately sold later during 2010. No impairments were recorded in 2011.

Depreciation and Amortization. Depreciation and amortization expenses were $125.4 million for the year ended December 31, 2011 compared to $111.6 million for the year ended December 31, 2010, an increase of $13.7 million, or 12.3%. The increase of $13.7 million includes $13.4 million due to intangible amortization related to a downward revision in future estimated throughput volumes attributable to the dedicated acreage purchased with its gathering system in north Texas. In addition, depreciation increased $0.3 million primarily due to an increase of assets placed in service in the Partnership's north Texas and LIG regions.

Interest Expense. Interest expense was $79.2 million for the year ended December 31, 2011 compared to $87.0 million for the year ended December 31, 2010, a decrease of $7.8 million, or 9.0%. Net interest expense consists of the following (in millions):

	Years Ended December 31,	
	2011	**2010**
Senior notes (secured and unsecured)	$64.3	$ 62.5
Paid-in-kind interest on senior secured notes	—	1.4
Bank credit facility	5.5	10.0
Series B secured notes	—	1.1
Capitalized interest	(0.9)	(0.1)
Mark to market interest rate swaps	—	(22.4)
Realized interest rate swap losses	—	26.5
Amortization of debt issue costs	8.3	6.6
Other	2.0	1.4
Total	$79.2	$ 87.0

Income Taxes. We provide for income taxes using the liability method. Accordingly, deferred taxes are recorded for the differences between the tax and book basis of assets and liabilities that will reverse in future periods. An income tax benefit of $2.8 million was recorded on the loss from operations (net of non-controlling interest) for the year ended December 31, 2011. A net income tax benefit of $6.0 million was also recorded on loss from operation (net of non-controlling interest) for the year ended December 31, 2010.

Interest of Non-Controlling Partners in the Partnership's Net Income (Loss) from Continuing Operations. The interest of non-controlling partners in the Partnership's net income was $4.7 million for the year ended December 31, 2011 compared to a net loss of $9.9 million for the year ended December 31, 2010 due to the changes shown in the following summary (in millions):

	Years Ended December 31,	
	2011	2010
Net loss from continuing operations for the Partnership	$(2.4)	$(25.8)
(Income) allocation to CEI for the general partner incentive distribution	(2.4)	(0.1)
Stock-based compensation costs allocated to CEI for its stock options and restricted stock granted to Partnership officers, employees and directors	3.1	3.9
Loss allocation to CEI for its 2% general partner share of Partnership loss	—	0.6
Net loss allocable to limited partners	(1.7)	(21.4)
Less: CEI's share of net (income) loss allocable to limited partners	6.4	11.5
Non-controlling partners' share of Partnership net income (loss) from continuing operations (including the Partnership's income attributed to preferred unitholders)	$ 4.7	$ (9.9)

Year ended December 31, 2010 Compared to Year ended December 31, 2009

Gross Operating Margin. Gross operating margin was $338.3 million for the year ended December 31, 2010 compared to $311.2 million for the year ended December 31, 2009, an increase of $27.1 million, or 8.7%. The increase was primarily due to higher margins on the Partnership's gathering and transmission throughput volume, as well as a favorable NGL market throughout the year. The following provides additional details regarding this change in gross operating margin:

- The LIG segment contributed gross operating margin growth of $16.6 million for the year ended December 31, 2010 over the same period in December 31, 2009. The gathering and transmission assets generated approximately $11.6 million of gross operating margin growth primarily due to improved pricing and higher volumes on the northern part of the system. The improved processing environment contributed to a gain in the gross operating margins for the LIG processing plants for the period. The Plaquemine and Gibson plants had gross operating margin gains of $2.9 million and $2.0 million, respectively.

- The NTX segment had gross operating margin increase of $2.8 million for the year ended December 31, 2010. A $3.7 million charge associated with an adverse arbitration award was included in 2009. Increased losses of $4.5 million under a certain supply agreement were offset by improvements in a number of areas that included enhanced liquids recoveries and unit margins, in addition to better processing margins.

- The improved processing and NGL marketing environment contributed to a $13.7 million increase in gross operating margin for the PNGL segment for the comparative periods. Fractionation and marketing activity generated a gross operating margin increase of approximately $10.0 million. In addition to the improved marketing environment, the inlet volume supplied to the fractionators was significantly increased through deliveries from rail cars and trucks. The Eunice and Pelican processing plants contributed gross operating margin increases of $2.9 million and $2.4 million, respectively. The Sabine Pass plant had a gross operating margin decline of $2.2 million due to a decrease in inlet volumes.

- The corporate segment reported a gross operating margin decrease of approximately $6.0 million for the year ended December 31, 2010 over the same period in 2009. The Crosstex Pipeline system in east Texas which was sold in the first quarter of 2010, created a negative gross operating margin variance of $5.8 million when compared to the prior period.

Operating Expenses. Operating expenses were $105.1 million for the year ended December 31, 2010 compared to $110.4 million for the year ended December 31, 2009, a decrease of $5.3 million, or 4.8%. The decrease is primarily the result of the following:

- the Partnership purchased the Eunice plant in late 2009 that resulted in $9.5 million decrease in rent expense;
- the Partnership sold its east Texas system which was not considered discontinued operations early in 2010 and this resulted in $3.9 million of reduced operating expenses;
- the Partnership was successful in renegotiating its existing compressor leases that resulted in $1.3 million of cost savings;
- the Partnership has expanded its Louisiana operations which caused operating expenses to increase by approximately $4.9 million;
- the Partnership experienced an increase in its operating expenses of $1.8 million related to ad valorem taxes, insurance costs and regulatory costs; and
- the Partnership's repairs and maintenance costs increased operating expenses by $3.3 million in 2010 over 2009.

General and Administrative Expenses. General and administrative expenses were $51.2 million for the year ended December 31, 2010 compared to $62.5 million for the year ended December 31, 2009, a decrease of $11.3 million, or 18.1%. The decrease is primarily a result of the following:

- the Partnership reduced its workforce in 2009 which resulted in a decrease of $9.4 million in labor and benefits; and
- the Partnership lowered its legal and professional costs by $2.4 million in 2010.

Gain on sale of Property from Continuing Operations. Gains on sale of property were $13.9 million for the year ended December 31, 2010 compared to $0.7 million for the year ended December 31, 2009. The gain on sale of property for the year ended December 31, 2010 was related to the sale of the Partnership's east Texas assets in January 2010.

Gain/Loss on Derivatives. Loss on derivatives was $9.1 million for the year ended December 31, 2010 compared to a gain of $3.0 million for the year ended December 31, 2009. The derivative transaction types contributing to the net (gain) loss are as follows (in millions):

	Years Ended December 31,			
	2010		2009	
(Gain) Loss on Derivatives:	Total	Realized	Total	Realized
Basis swaps	$5.6	$2.3	$(4.4)	$(2.5)
Processing margin hedges	3.5	5.5	1.4	(2.2)
Other	—	0.1	(0.3)	(1.4)
	$9.1	$7.9	$(3.3)	$(6.1)
Derivative losses included in income from discontinued operations	—	—	0.3	0.5
Net (gain) loss from continuing operations	$9.1	$7.9	$(3.0)	$(5.6)

Impairments. Impairment expense was $1.3 million during the year ended December 31, 2010, compared to $2.9 million for the year ended December 31, 2009. During 2009, impairments totaling $2.9 million were taken on the Bear Creek processing plant and the Vermillion treating plant to bring the fair value of the plants to a marketable value for these idle assets, which were subsequently sold. During 2010, impairments totaling $1.3 million were taken on excess pipe that was ultimately sold later during 2010.

Depreciation and Amortization. Depreciation and amortization expenses were $111.6 million for the year ended December 31, 2010 compared to $119.2 million for the year ended December 31, 2009, a decrease of $7.5 million, or 6.3%. The decrease of $7.5 million was the result of an increase in estimated depreciable lives for certain of our processing plants based on 2009 depreciation study that resulted in a depreciation expense decrease of $9.1 million partially offset by $1.6 million increase in depreciation on the Eunice natural gas processing plants and fractionation facility purchased during fourth quarter 2009.

Interest Expense. Interest expense was $87.0 million for the year ended December 31, 2010 compared to $95.1 million for the year ended December 31, 2009, a decrease of $8.1 million, or 8.5%. Net interest expense consists of the following (in millions):

	Years Ended December 31,	
	2010	2009
Senior notes (secured and unsecured)	$ 62.5	$28.8
Paid-in-kind interest on senior secured notes	1.4	4.9
Bank credit facility	10.0	35.4
Series B secured notes	1.1	0.4
Capitalized interest	(0.1)	(1.1)
Mark to market interest rate swaps	(22.4)	(0.8)
Realized interest rate swap losses	26.5	19.0
Interest income	—	(0.2)
Amortization of debt issue costs	6.6	7.6
Other	1.4	1.1
Total	$ 87.0	$95.1

Loss on Extinguishment of Debt. Loss on extinguishment of debt was $14.7 million for year ended December 31, 2010 as compared to $4.7 million in 2009. In February 2010, the Partnership repaid its prior credit facility and senior secured notes which resulted in make-whole interest payments on its senior secured notes and the write-off of unamortized debt costs totaling $14.7 million. The loss of $4.7 million on extinguishment of debt incurred in the year ended December 31, 2009 related to the amendment of its prior credit facility and the senior secured notes in February 2009.

Income Taxes. We provide for income taxes using the liability method. Accordingly, deferred taxes are recorded for the differences between the tax and book basis of assets and liabilities that will reverse in future periods. A net income tax benefit of $6.0 million was recorded on the loss from operations (net of non-controlling interest) for the year ended December 31, 2010. A net income benefit of $6.0 million was also recorded for the year ended December 31, 2009 comprised of an income tax benefit of $10.6 million recorded on the loss from continuing operations (net of non-controlling interest) partially offset by a tax expense of $4.6 million attributable to the conversion of the Partnership's senior subordinated series D units to common units in 2009.

Discontinued Operations. During 2009, the Partnership sold non-strategic assets and used the proceeds from such sales to repay long-term indebtedness.

Assets	Date of Sale
Oklahoma assets (Arkoma system)	February 2009
Alabama, Mississippi and south Texas assets	August 2009
Treating assets	October 2009

In accordance with FASB ASC 360-10-05-4, the results of operations related to these assets (except the Oklahoma assets, which were immaterial to the financial statement presentations) are presented in income from discontinued operations for the comparative periods in the statements of operations. Revenues, operating expenses, general and administrative expenses associated directly to the assets sold, depreciation and amortization, allocated Texas margin tax and allocated interest are reflected in the income from discontinued operations. Following are the components of revenues and earnings from discontinued operations and operating data (dollars in millions):

	Years Ended December 31, 2009
Midstream revenues	$ 327.2
Treating revenues	$ 45.5
Income from discontinued operations, net of tax	$ (1.5)
Gain from sale of discontinued operations, net of tax	$ 160.0
Gathering and Transmission Volumes (MMBtu/d)	564,000
Processing Volumes (MMBtu/d)	191,000

Interest of Non-Controlling Partners in the Partnership's Net Income (Loss) from Continuing Operations. The interest of non-controlling partners in the Partnership's net loss was $9.9 million for the year ended December 31, 2010 compared to a net loss of $48.1 million for the year ended December 31, 2009 due to the changes shown in the following summary (in millions):

	Years Ended December 31,	
	2010	**2009**
Net loss from continuing operations for the Partnership	$(25.8)	$(77.5)
(Income) allocation to CEI for the general partner incentive distribution	(0.1)	—
Stock-based compensation costs allocated to CEI for its stock options and restricted stock granted to Partnership officers, employees and directors	3.9	3.0
Loss allocation to CEI for its 2% general partner share of Partnership loss	0.6	1.5
Net loss allocable to limited partners	(21.4)	(73.0)
Less: CEI's share of net (income) loss allocable to limited partners	11.5	24.9
Non-controlling partners' share of Partnership net loss from continuing operations	$ (9.9)	$(48.1)

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. See Note 2 of the Notes to Consolidated Financial Statements for further details on our accounting policies.

Revenue Recognition and Commodity Risk Management. The Partnership recognizes revenue for sales or services at the time the natural gas or NGLs are delivered or at the time the service is performed. It generally accrues one month 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.

The Partnership utilizes 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. The Partnership uses 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. The Partnership believes that its accrual process for sales and purchases provides a reasonable estimate of such sales and purchases.

The Partnership engages in price risk management activities in order to minimize the risk from market fluctuations in the price of natural gas and NGLs. It also manages its 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 its future commitments and significantly reduce its risk to the movement in natural gas and NGL prices.

The Partnership uses derivatives to hedge against changes in cash flows related to product prices, as opposed to their use for trading purposes. FASB ASC 815 requires that 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.

The Partnership conducts "off-system" gas marketing operations as a service to producers on systems that it does not own. It refers to these activities as part of 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 revenue and cost of sales for these activities are included in revenue on a net basis in the statement of operations.

The Partnership manages its 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, the Partnership is subject to counter-party risk for both the physical and financial contracts. Our energy trading contracts qualify as derivatives, and it uses 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.

Sales of Securities by Subsidiaries. Prior to 2009, we recognized gains and losses in the consolidated statements of operations resulting from subsidiary sales of additional equity interest, including the Partnership's limited partnership units to unrelated parties. Pursuant to new accounting guidance adopted effective January 1, 2009, we reflect changes in our ownership interest in the Partnership as equity transactions. The carrying amount of the non-controlling interest is adjusted to reflect the change in our ownership interest in the Partnership. Any difference between the fair value of the consideration received and the amount by which the non-controlling interest is adjusted is recognized in additional paid-in capital.

Impairment of Long-Lived Assets. In accordance with FASB ASC 360-10-05, the Partnership evaluates 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 the Partnership's long-lived assets has occurred, we must estimate the undiscounted cash flows attributable to the asset. The 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;
- the Partnership's 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 the Partnership's cash flows, which could require us to record an impairment of an asset.

Depreciation Expense and Cost Capitalization. The Partnership's assets consist primarily of natural gas gathering pipelines, processing plants, and transmission pipelines. The Partnership capitalizes all construction-related direct labor and material costs, as well as indirect construction costs. Indirect construction costs include general engineering and the costs of funds used in construction. Capitalized interest represents the cost of funds used to finance the construction of new facilities and is expensed over the life of the constructed assets through the recording of depreciation expense. The Partnership capitalizes the costs of renewals and betterments that extend the useful life, while it expenses the costs of repairs, replacements and maintenance projects as incurred.

The Partnership generally computes depreciation using the straight-line method over the estimated useful life of the assets. Certain assets such as land, NGL line pack and natural gas line pack are non-depreciable. The computation of depreciation expense requires judgment regarding the estimated useful lives and salvage value of assets. As circumstances warrant, depreciation estimates may be reviewed to determine if any changes are needed. Such changes could involve an increase or decrease in estimated useful lives or salvage values, which would impact future depreciation expense.

Liquidity and Capital Resources

Cash flow presented in the liquidity discussions below includes cash flow from discontinued operations for the year ended December 31, 2009.

Cash Flows from Operating Activities. Net cash provided by operating activities was $141.3 million, $84.8 million and $78.9 million for the years ended December 31, 2011, 2010 and 2009, respectively. Income before non-cash income and expenses and changes in working capital for 2011, 2010 and 2009 were as follows (in millions):

	Years Ended December 31,		
	2011	2010	2009
Income before non-cash income and expenses	$136.5	$58.8	$87.3
Changes in working capital	$ 4.8	$26.0	$(8.4)

The primary reason for the increase in cash flow from income before non-cash income and expenses of $77.0 million from 2010 to 2011 relates to payments made in 2010 for settlement of interest rate swaps, make-whole payments and PIK notes combined with an increase in 2011 gross operating margin and a decrease in interest expense. The primary reason for the decreased cash flow from income before non-cash income and expenses of $28.5 million from 2010 to 2009 relates to payment for settlement of interest rate swaps, make-whole payments and PIK notes in 2010.

The change in working capital for 2011 and 2009 primarily relates to normal fluctuations in trade receivable and payable balances due to timing of collections and payments. The change in working capital for 2010 primarily relates to accrued interest on long-term debt. The Partnership pays interest semi-annually in February and August on the Partnership's senior unsecured notes which caused the balance in accrued interest to increase by approximately $19.0 million in 2010 as compared to 2009.

Cash Flows from Investing Activities. Net cash used in investing activities was $132.1 million for the year ended December 31, 2011 and net cash provided by investing activities was $14.6 million for the year ended December 31, 2010. Net cash used in investing activity was $379.9 million for the year ended December 31, 2009. Cash flows from investing activities for the years ended December 31, 2011, 2010 and 2009 included proceeds from property sales of $0.5 million, $60.2 million and $503.9 million, respectively. The east Texas assets and a non-operational processing plant held in inventory were the primary assets sold in 2010 for $39.8 million and $19.5 million, respectively. In 2009, the Partnership sold its Arkoma system for approximately $10.7 million, the Partnership sold its midstream assets in Alabama, Mississippi and south Texas for approximately $217.6 million and the Partnership sold its natural gas treating business for $265.4 million. The Partnership's primary use of cash related to investing activities for the years ended December 31, 2011, 2010 and 2009 were capital expenditures and acquisitions, net of accrued amounts, and an investment in HEP as follows (in millions):

	Years Ended December 31,		
	2011	2010	2009
Growth capital expenditures	$ 85.0	$37.4	$ 90.5
Acquisition and asset purchases	—	—	35.1
Maintenance capital expenditures	12.6	10.8	10.9
Investment in Howard Energy Partners	35.0	—	—
Total	$132.6	$48.2	$136.5

Cash Flows from Financing Activities. Net cash used in financing activities was $1.6 million, $87.4 million, and $462.0 million for the years ended December 31, 2011, 2010, and 2009, respectively. Our primary financing activities consist of the following (in millions):

	Years Ended December 31,		
	2011	2010	2009
Net borrowings (repayments) under bank credit facilities(1)	$85.0	$(529.6)	$(254.4)
Senior secured note repayments(2)	—	(316.5)	(163.2)
Senior unsecured note borrowings (net of discount on the note)	—	711.5	—
Series B secured note repayment	(7.1)	(11.0)	—
Net borrowings (repayments) under capital lease obligations	(3.1)	(2.4)	(0.7)
Debt refinancing costs	(4.0)	(28.6)	(15.0)
Issuance of preferred units	—	120.8	—

(1) Year ended December 31, 2009 includes a $143.0 million and $173.3 million payment due to the sale of the Alabama, Mississippi and south Texas assets and the Treating assets, respectively.

(2) Year ended December 31, 2009 includes a $69.0 million and $84.8 million payment due to sale of the Alabama, Mississippi and south Texas assets and the Treating assets, respectively.

Dividends to shareholders and distributions to non-controlling partners in the Partnership represent our primary use of cash in financing activities. Total cash distributions made during the last three years were as follows (in millions):

	Years Ended December 31,		
	2011	2010	2009
Dividends to shareholders	$17.9	$ 3.4	$ 4.2
Distributions to non-controlling partners	58.2	19.0	7.6
Total	$76.1	$22.4	$11.8

In order to reduce our interest costs, the Partnership does 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 the Partnership's revolving credit facility. The Partnership borrows money under our $635.0 million new credit facility to fund checks as they are presented. Based on the January amendment to increase the credit facility borrowing capacity to $635.0 million and borrowings outstanding as of December 31, 2011, the Partnership's available borrowings would be $481.0 million. Changes in drafts payable for 2011, 2010 and 2009 were as follows (in millions):

	Years Ended December 31,		
	2011	2010	2009
Increase (decrease) in drafts payable	$5.9	$(5.1)	$(16.3)

Working Capital Deficit. We had a working capital deficit of $16.8 million as of December 31, 2011. Changes in working capital may fluctuate significantly between periods even though the Partnership's trade receivables and payables are typically collected and paid in 30 to 60 day pay cycles. A large volume of its revenues are collected and a large volume of its gas purchases are paid near each month end or the first few days of the following month so receivable and payable balances at any month end may fluctuate significantly depending on the timing of these receipts and payments. In addition, although the Partnership strives to minimize natural gas and NGLs in inventory, these working inventory balances may fluctuate significantly from period to period due to operational reasons and due to changes in natural gas and NGL prices. The changes in working capital during the years ended December 31, 2011 and 2010 are due to the impact of the fluctuations discussed above.

January 2010 Sale of Preferred Units. On January 19, 2010, the Partnership issued approximately $125.0 million of Series A Convertible Preferred Units to an affiliate of Blackstone/GSO Capital Solutions for net proceeds of $120.8 million. Crosstex Energy, GP, L.P. made a general partner contribution of $2.6 million in connection with the issuance to maintain its 2% general partner interest. The 14,705,882 preferred units are convertible by the holders thereof at any time into common units on a one-for-one basis, subject to certain adjustments in the event of certain dilutive issuances of common units. They are entitled to a quarterly distribution that is the greater of $0.2125 per unit or the amount of the quarterly distribution per unit paid to common unitholders, subject to certain adjustments. Such quarterly distribution may be paid in cash, in additional preferred units issued in kind or any combination thereof, provided that the distribution may not be paid in additional preferred units if the Partnership pays a cash distribution on common units.

Potential Changes in use of Sabine Plant during 2012. Currently, its Sabine plant has a contract with a third-party to fractionate the raw-make NGLs produced by the plant. The Partnership has been unsuccessful in renewing this contract, which expires on March 1, 2012. The Partnership has an interim solution to continue to provide for fractionation of the NGLs produced by the Sabine plant. Ultimately, the Partnership plans to connect the Sabine gas supply to its Eunice plant, which can process the gas and fractionate the produced NGLs. If this processing change is made, the Partnership will likely cease operating the Sabine plant. Although the Partnership does not have specific plans at this time to relocate the Sabine plant once it is idled, the Partnership may consider it for utilization elsewhere in its operations. The net book value of the Sabine plant was $34.0 million as of December 31, 2011. If the plant is idled on a long-term basis as contemplated above, an impairment may be recorded to expense the non-recoverable costs associated with the plant's current location, which are estimated to be less than $15.0 million based on the net book value as of December 31, 2011.

Capital Projects for 2012. The Partnership's 2012 capital budget includes approximately $294 million of identified growth projects and capital interest. The Partnership's primary capital projects for 2012 include the expansion of the Cajun Sibon NGL Pipeline and construction of processing plants in the Permian Basin. The first project is the Partnership's Cajun-Sibon NGL pipeline expansion with an estimated cost of $230.0 million and an estimated completion date during the first half of 2013. The second project is the Partnership's 50 percent owned Deadwood Plant and the completion of its 100 percent owned Mesquite Terminal facilities in the Permian Basin with a capital spend of approximately $45.0 million in 2012. During 2011, the Partnership invested in several capital projects. The Partnership's 2011 capital projects included its north Texas expansions with a total cost of $44.2 million, and its Mesquite Terminal and Deadwood Plant projects with a total cost of $26.9 million. Also, the Partnership made an equity investment in Howard Energy for an initial capital contribution of $35.0 million. See "Item 1. Busines—Recent Growth Developments" for further details.

In 2012, it is possible that not all of the planned projects will be commenced or completed. The Partnership expects to fund our maintenance capital expenditures of $17.0 million from operating cash flows. We provide for income taxes using the liability method. Accordingly, deferred taxes are recorded for the differences between the tax and book basis of assets and liabilities that will reverse in future periods. The Partnership expects to fund the growth capital expenditures from the proceeds of borrowings under the Partnership's bank credit facility discussed below, and from other debt and equity sources. Our ability to pay dividends to our shareholders, and the Partnership's ability to fund planned capital expenditures and to make acquisitions will depend upon its future operating performance, which will be affected by prevailing economic conditions in the industry and financial, business and other factors, some of which are beyond the Partnership's control.

Off-Balance Sheet Arrangements. We had no off-balance sheet arrangements as of December 31, 2011, 2010 and 2009.

Total Contractual Cash Obligations. A summary of the Partnership's total contractual cash obligations as of December 31, 2011, is as follows (in millions):

	Payments Due by Period						
	Total	2012	2013	2014	2015	2016	Thereafter
Long-term debt obligations	$ 810.0	$ —	$ —	$ —	$ —	$ 85.0	$725.0
Interest payable on fixed long-term debt obligations	417.1	64.3	64.3	64.3	64.3	64.3	95.6
Capital lease obligations	35.1	4.6	4.6	4.6	4.6	4.6	12.1
Operating lease obligations	41.3	13.2	7.7	5.9	4.5	4.5	5.5
Purchase obligations	4.1	4.1	—	—	—	—	—
Uncertain tax position obligations	4.2	4.2	—	—	—	—	—
Total contractual obligations	$1,311.8	$90.4	$76.6	$74.8	$73.4	$158.4	$838.2

The above table does not include any physical or financial contract purchase commitments for natural gas due to the nature of both the price and volume components of such purchases, which vary on a daily or monthly basis. Additionally, we do not have contractual commitments for fixed price and/or fixed quantities of any material amount.

The interest payable under the Partnership's credit facility is not reflected in the above table because such amounts depend on outstanding balances and interest rates, which will vary from time to time. However, given the same borrowing amount and rates in effect at December 31, 2011 the Partnership's cash obligation for interest expense on its credit facility would be approximately $2.0 million per year.

Description of Indebtedness

As of December 31, 2011 and 2010, long-term debt consisted of the following (in millions):

	2011	2010
Bank credit facility (due 2016), interest based on Prime and/or LIBOR plus an applicable margin, interest rate at December 31, 2011 and December 31, 2010 was 2.9% and 4.0%, respectively	$ 85.0	$ —
Senior unsecured notes, net of discount of $11.6 million and $13.5 million, respectively, which bear interest at the rate of 8.875%	713.4	711.5
Series B secured note assumed in the Eunice transaction, which bore interest at the rate of 9.5%	—	7.1
	798.4	718.6
Less current portion	—	(7.1)
Debt classified as long-term	$798.4	$711.5

Credit Facility. The Partnership made three amendments to its bank credit facility in May 2011, July 2011 and January 2012. The amendments contained the following changes:

- Increased borrowing capacity from $420.0 million to $635.0 million;
- Extended maturity from February 2014 to May 2016;
- Increased the maximum permitted leverage ratio to 5.00 to 1.00;
- Decreased the minimum consolidated interest rate coverage ratio during certain fiscal quarters;
- Decreased the interest rates;
- Permitted Apache Midstream LLC ("Apache") to have a first priority lien on certain assets that are the subject of a joint interest arrangement between Apache and Crosstex Permian, LLC ("Permian");
- Increased the Partnership's ability to make investments in joint ventures and subsidiaries; without such joint ventures and subsidiaries becoming guarantors under the credit agreement; and
- Allowed the Partnership to use multiple banks as letter of credit issuers.

As of December 31, 2011, there was $85.0 million of borrowing and $69.0 million in outstanding letters of credit, under the bank credit facility leaving approximately $331.0 million available for future borrowing based on a borrowing capacity of $485.0 million. Based on the January amendment to increase the credit facility borrowing capacity to $635.0 million and borrowings outstanding as of December 31, 2011, the Partnership's available borrowing would be $481.0 million.

The credit facility is guaranteed by substantially all of the Partnership's subsidiaries and is secured by first priority liens on substantially all of the Partnership's assets and those of the guarantors, including all material pipeline, gas gathering and processing assets, all material working capital assets and a pledge of all of its equity interests in substantially all 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. The credit facility requires mandatory prepayments of amounts outstanding thereunder with the net proceeds of certain asset sales, extraordinary receipts, equity issuances and debt incurrences, but these mandatory prepayments do not require any reduction of the lenders' commitments under the credit facility.

Under the amended credit facility, borrowings bear interest at the Partnership's option at the Eurodollar Rate (the British Bankers Association LIBOR Rate) plus an applicable margin or the Base Rate (the highest of the Federal Funds Rate plus 0.50%, the 30-day Eurodollar Rate plus 1.0%, or the administrative agent's prime rate) plus an applicable margin. The Partnership pays a per annum fee (as described below) on all letters of credit issued under the amended credit facility and a commitment fee of between 0.375% and 0.50% per annum on the unused availability under the amended credit facility. The commitment fee, letter of credit fee and the applicable margins for the interest rate vary quarterly based on the Partnership's leverage ratio (as defined in the credit facility, being generally computed as the ratio of total funded debt to consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges) and are as follows:

Leverage Ratio	Base Rate Loans	Eurodollar Rate Loans	Letter of Credit Fees
Greater than or equal to 4.50 to 1.00	2.00%	3.00%	3.00%
Greater than or equal to 4.00 to 1.00 and less than 4.50 to 1.00	1.75%	2.75%	2.75%
Greater than or equal to 3.50 to 1.00 and less than 4.00 to 1.00	1.50%	2.50%	2.50%
Greater than or equal to 3.00 to 1.00 and less than 3.50 to 1.00	1.25%	2.25%	2.25%
Less than 3.00 to 1.00	1.00%	2.00%	2.00%

Based on the forecasted leverage ratio of 4.00 to 1.00 for 2012, the Partnership expects the margin for the interest rate and letter of credit fee to be in line with the applicable rates above. The credit facility does not have a floor for the Base Rate or the Eurodollar Rate.

The amended credit facility includes financial covenants that are tested on a quarterly basis, based on the rolling four-quarter period that ends on the last day of each fiscal quarter. The maximum permitted leverage ratio (as defined in the credit facility, but generally computed as the ratio of total secured funded debt to consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges) is 5.00 to 1.00. The minimum consolidated interest coverage ratio (as defined in the credit facility, but generally computed as the ratio of consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges to consolidated interest charges) is as follows:

- 2.25 to 1.00 for the fiscal quarters ending March 31, 2012 through June 30, 2013;
- 2.50 to 1.00 for the fiscal quarter ended September 30, 2013 and each fiscal quarter thereafter.

In addition, the credit facility contains various covenants that, among other restrictions, limit the Partnership's ability to:

- grant or assume liens;
- make investments;
- incur or assume indebtedness;
- engage in mergers or acquisitions;

- sell, transfer, assign or convey assets;
- repurchase its equity, make distributions and certain other restricted payments;
- change the nature of its business;
- engage in transactions with affiliates;
- enter into certain burdensome agreements;
- make certain amendments to the omnibus agreement, the Partnership's or its subsidiaries' organizational documents;
- prepay the senior unsecured notes and certain other indebtedness; and
- enter into certain hedging contracts.

The credit facility permits the Partnership to make quarterly distributions to unitholders so long as no default exists under the credit facility.

Each of the following is an event of default under the credit facility:

- failure to pay any principal, interest, fees, expenses or other amounts when due;
- failure to meet the quarterly financial covenants;
- failure to observe any other agreement, obligation, or covenant in the credit facility or any related loan document, subject to cure periods for certain failures;
- the failure of any representation or warranty to be materially true and correct when made;
- the Partnership or any of its subsidiaries default under other indebtedness that exceeds a threshold amount;
- judgments against the Partnership or any of its material subsidiaries, in excess of a threshold amount;
- certain ERISA events involving the Partnership or any of its material subsidiaries, in excess of a threshold amount;
- bankruptcy or other insolvency events involving the Partnership or any of its material subsidiaries; and
- a change in control (as defined in the credit facility).

If an event of default relating to bankruptcy or other insolvency events occur, all indebtedness under the credit facility will immediately become due and payable. If any other event of default exists under the credit facility, the lenders may accelerate the maturity of the obligations outstanding under the credit facility and exercise other rights and remedies. In addition, if any event of default exists under the credit facility, the lenders may commence foreclosure or other actions against the collateral.

If any default occurs under the credit facility, or if the Partnership is unable to make any of the representations and warranties in the credit facility, the Partnership will be unable to borrow funds or have letters of credit issued under the credit facility.

The Partnership expects to be in compliance with the covenants in the credit facility for at least the next twelve months.

Series B Secured Note. On October 20, 2009, the Partnership acquired the Eunice natural gas liquids processing plant and fractionation facility which included an $18.1 million series B secured note. The Partnership paid $11.0 million of principal on the series B secured note in May 2010 and paid the remaining $7.1 million in May 2011.

Senior Unsecured Notes. On February 10, 2010, the Partnership issued $725.0 million in aggregate principal amount of 8.875% senior unsecured notes (the "notes") due on February 15, 2018 pursuant to Rule 144A and Regulation S under the Securities Act at an issue price of 97.907% to yield 9.25% to maturity including the original issue discount (OID). Net proceeds from the sale of the notes of $689.7 million (net of transaction costs and OID), together with borrowings under the credit facility discussed above, were used to repay in full amounts outstanding under the prior bank credit facility and senior secured notes and to pay related fees, costs and expenses, including the settlement of interest rate swaps associated with the prior credit facility. Interest payments on the notes are due semi-annually in arrears in February and August.

The indenture governing the notes contains covenants that, among other things, limit the Partnership's ability and the ability of certain of its subsidiaries to:

- sell assets including equity interests in its subsidiaries;
- pay distributions on, redeem or repurchase units or redeem or repurchase its subordinated debt (as discussed in more detail below);
- make investments;
- incur or guarantee additional indebtedness or issue preferred units;
- create or incur certain liens;
- enter into agreements that restrict distributions or other payments from its restricted subsidiaries to the Partnership;
- consolidate, merge or transfer all or substantially all of its assets;
- engage in transactions with affiliates;
- create unrestricted subsidiaries;
- enter into sale and leaseback transactions; or
- engage in certain business activities.

The indenture provides that if the Partnership's fixed charge coverage ratio (the ratio of consolidated cash flow to fixed charges, which generally represents the ratio of adjusted EBITDA to interest charges with further adjustments as defined per the indenture) for the most recently ended four full fiscal quarters is not less than 2.0 to 1.0, the Partnership will be permitted to pay distributions to its unitholders in an amount equal to available cash from operating surplus (each as defined in our partnership agreement) with respect to its preceding fiscal quarter plus a number of items, including the net cash proceeds received by the Partnership as a capital contribution or from the issuance of equity interests since the date of the indenture, to the extent not previously expended. If its fixed charge coverage ratio is less than 2.0 to 1.0, the Partnership will be able to pay distributions to its unitholders in an amount equal to an $80.0 million basket (less amounts previously expended pursuant to such basket), plus the same number of items discussed in the preceding sentence to the extent not previously expended. The Partnership expects to be in compliance with this ratio for at least the next twelve months.

If the notes achieve an investment grade rating from each of Moody's Investors Service, Inc. and Standard & Poor's Ratings Services, many of the covenants discussed above will terminate.

The Partnership may redeem up to 35% of the notes at any time prior to February 15, 2013 with the cash proceeds from equity offerings at a redemption price of 108.875% of the principal amount of the notes (plus accrued and unpaid interest to the redemption date) provided that:

- at least 65% of the aggregate principal amount of the senior notes remains outstanding immediately after the occurrence of such redemption; and
- the redemption occurs within 120 days of the date of the closing of the equity offering.

Prior to February 15, 2014, the Partnership may redeem the notes, in whole or in part, at a "make-whole" redemption price. On or after February 15, 2014, the Partnership may redeem all or a part of the notes at redemption prices (expressed as percentages of principal amount) equal to 104.438% for the twelve-month period beginning on February 15, 2014, 102.219% for the twelve-month period beginning February 15, 2015 and 100.00% for the twelve-month period beginning on February 15, 2016 and at any time thereafter, plus accrued and unpaid interest, if any, to the applicable redemption date on the notes.

Each of the following is an event of default under the indenture:

- failure to pay any principal or interest when due;
- failure to observe any other agreement, obligation, or other covenant in the indenture, subject to the cure periods for certain failures;
- the Partnership or any of its subsidiaries' default under other indebtedness that exceeds a certain threshold amount;
- failures by the Partnership or any of its subsidiaries to pay final judgments that exceed a certain threshold amount; and
- bankruptcy or other insolvency events involving the Partnership or any of its material subsidiaries.

If an event of default relating to bankruptcy or other insolvency events occurs, the senior unsecured notes will immediately become due and payable. If any other event of default exists under the indenture, the trustee under the indenture or the holders of the senior unsecured notes may accelerate the maturity of the senior unsecured notes and exercise other rights and remedies.

Credit Risk

Risks of nonpayment and nonperformance by the Partnership's customers are a major concern in its business. The Partnership is subject to risks of loss resulting from nonpayment or nonperformance by its customers and other counterparties, such as lenders and hedging counterparties. Any increase in the nonpayment and nonperformance by its customers could adversely affect the results of operations and reduce the Partnership's ability to make distributions to its unitholders.

Inflation

Inflation in the United States has been relatively low in recent years in the economy as a whole. The midstream natural gas industry experienced an increase in labor and material costs during 2009, but 2010 and 2011 remained relatively unchanged. These increases did not have a material impact on our results of operations for the periods presented. 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

The Partnership's operations are subject to environmental laws and regulations adopted by various governmental authorities in the jurisdictions in which these operations are conducted. We believe the Partnership is 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."

Contingencies

On June 7, 2010, Formosa Plastics Corporation, Texas, Formosa Plastics Corporation America, Formosa Utility Venture, Ltd., and Nan Ya Plastics Corporation, America filed a lawsuit against Crosstex Energy, Inc., Crosstex Energy, L.P., Crosstex Energy GP, L.P., Crosstex Energy GP, LLC, Crosstex Energy Services, L.P., and Crosstex Gulf Coast Marketing, Ltd. In the 24th Judicial District Court of Calhoun County, Texas, asserting claims for negligence, *res ipsa loquitor*, products liability and strict liability relating to the alleged receipt by the plaintiffs of natural gas liquids into their facilities from facilities operated by the Partnership. The amended petition alleges that the plaintiffs have incurred approximately $35.0 million in damages, including damage to equipment and lost profits. The Partnership has submitted the claim to its insurance carriers and intends to vigorously defend the lawsuit. The Partnership believes that any recovery would be within applicable policy limits. Although it is not possible to predict the ultimate outcome of this matter, the Partnership does not expect that an award in this matter will have a material adverse impact on its consolidated results of operations or financial condition.

At times, the Partnership's gas-utility subsidiaries acquire pipeline easements and other property rights by exercising rights of eminent domain provided under state law. As a result, the Partnership (or its subsidiaries) is a party to a number of lawsuits under which a court will determine the value of pipeline easements or other property interests obtained by the Partnership's gas utility subsidiaries by condemnation. Damage awards in these suits should reflect the value of the property interest acquired and the diminution in the value of the remaining property owned by the landowner. However, some landowners have alleged unique damage theories to inflate their damage claims or assert valuation methodologies that could result in damage awards in excess of the amounts anticipated. Although it is not possible to predict the ultimate outcomes of these matters, the Partnership does not expect that awards in these matters will have a material adverse impact on its consolidated results of operations or financial condition.

The Partnership (or its subsidiaries) is defending a number of lawsuits filed by owners of property located near processing facilities or compression facilities constructed by the Partnership as part of its systems. The suits generally allege that the facilities create a private nuisance and have damaged the value of surrounding property. Claims of this nature have arisen as a result of the industrial development of natural gas gathering, processing and treating facilities in urban and occupied rural areas. In January 2012, a plaintiff in one of these lawsuits was awarded a judgment of $2.0 million. The Partnership intends to appeal the matter and will post a bond to secure the judgment pending its resolution. The Partnership has accrued $2.0 million related to this matter as of December 31, 2011 and reflected the related expense in operating expenses in the fourth quarter of 2011.

Disclosure Regarding Forward-Looking Statements

This Annual Report on Form 10-K contains forward-looking statements 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 "forecast," "may," "believe," "will," "should," "plan," "predict," "anticipate," "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. The Partnership's primary market risk is the risk related to changes in the prices of natural gas and NGLs. In addition, it is also exposed to the risk of changes in interest rates on floating rate debt.

On July 21, 2010, President Obama signed the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Act") into law, a part of which relates to increased regulation of the markets for derivative products of the type the Partnership uses to manage areas of market risk. While the Commodity Futures Trading Commission has not yet completed its expected series of new regulations to implement the Act, Dodd-Frank may result in increased costs to the Partnership to implement our market risk management strategy.

Commodity Price Risk

The Partnership is subject to significant risks due to fluctuations in commodity prices. Its exposure to these risks is primarily in the gas processing component of its business. The Partnership currently processes gas under three main types of contractual arrangements:

1. *Processing margin contracts*: Under this type of contract, the Partnership pays the producer for the full amount of inlet gas to the plant, and makes 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") and the cost of fuel used in processing. The shrink and fuel losses are referred to as plant thermal reduction or PTR. The Partnership's 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. However, the Partnership mitigates its risk of processing natural gas when margins are negative primarily through its ability to bypass processing when it is not profitable for the Partnership, or by contracts that revert to a minimum fee for processing if the natural gas must be processed to meet pipeline quality specifications.
2. *Percent of liquids contracts*: Under these contracts, the Partnership receives 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, its margins from these contracts are greater during periods of high liquids prices. The Partnership's margins from processing cannot become negative under percent of liquids contracts, but do decline during periods of low NGL prices.
3. *Fee based contracts*: Under these contracts the Partnership has no commodity price exposure and are paid a fixed fee per unit of volume that is processed.

The gross operating margin presentation in the table below is calculated net of results from discontinued operations. Gas processing margins by contract types and gathering and transportation margins as a percent of total gross operating margin for the comparative year-to-date periods are as follows:

	Years Ended December 31,		
	2011	2010	2009
Gathering and transportation margin	56.6%	62.2%	65.8%
Gas processing margins:			
Processing margin	19.3%	12.9%	8.9%
Percent of liquids	10.7%	10.6%	13.2%
Fee based	13.4%	14.3%	12.1%
Total gas processing	43.4%	37.8%	34.2%
Total	100.0%	100.0%	100.0%

The Partnership has hedges in place at December 31, 2011 covering a portion of the liquids volumes it expects to receive under percent of liquids (POL) contracts. The hedges done via swaps are set forth in the following table. The relevant payment index price is the monthly average of the daily closing price for deliveries of commodities into Mont Belvieu, Texas as reported by the Oil Price Information Service (OPIS).

Period	Underlying	Notional Volume	We Pay	We Receive*	Fair Value Asset/(Liability)
					(In thousands)
January 2012 - December 2012	Ethane	46 (MBbls)	Index	$0.6367/gal	$(269)
January 2012 - December 2012	Propane	73 (MBbls)	Index	$1.3005/gal	(128)
January 2012 - December 2012	Normal Butane	39 (MBbls)	Index	$1.6855/gal	(221)
January 2012 - December 2012	Natural Gasoline	30 (MBbls)	Index	$2.2664/gal	67
*weighted average					$(551)

The Partnership has hedged its exposure to declines in prices for NGL volumes produced for its account. The NGL volumes hedged, as set forth above, focus on POL contracts. The Partnership hedges its POL exposure based on volumes it considers hedgeable (volumes committed under contracts that are long term in nature) versus total POL volumes that include volumes that may fluctuate due to contractual terms, such as contracts with month to month processing options. The Partnership has hedged 50.0% of its hedgeable volumes at risk through December 2012 (27.5% of total volumes at risk through December 2012).

The Partnership also has hedges in place at December 31, 2011 covering the fractionation spread risk related to its processing margin contracts as set forth in the following table:

Period	Underlying	Notional Volume	We Pay	We Receive	Fair Value Asset/(Liability)
					(In thousands)
January 2012 - December 2012	Ethane	122 (MBbls)	Index	$0.6972 /gal*	$ (257)
January 2012 - December 2012	Propane	106 (MBbls)	Index	$1.3185 /gal*	(108)
January 2012 - December 2012	Normal Butane	62 (MBbls)	Index	$1.7542 /gal*	(170)
January 2012 - December 2012	Natural Gasoline	51 (MBbls)	Index	$2.3249 /gal*	241
January 2012 - December 2012	Natural Gas	3,915(MMBtu/d)	$4.682 /MMBtu*	Index	(2,138)
*weighted average					$(2,432)

In relation to its fractionation spread risk, as set forth above, the Partnership has hedged 60.9% of its hedgeable liquids volumes at risk through December 2012 (15.7% of total liquids volumes at risk) and 63.6% of the related hedgeable PTR volumes through December 2012 (13.2% of total PTR volumes).

The Partnership is also subject to price risk to a lesser extent for fluctuations in natural gas prices with respect to a portion of its gathering and transport services. Approximately 5.1% of the natural gas the Partnership markets 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, the Partnership's resale margins are higher during periods of high natural gas prices and lower during periods of lower natural gas prices.

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

The Partnership's primary commodity risk management objective is to reduce volatility in its cash flows. The Partnership maintains a risk management committee, including members of senior management, which oversees all hedging activity. The Partnership enters into hedges for natural gas and NGLs using over-the-counter derivative financial instruments with only certain well-capitalized counterparties which have been approved by its risk management committee.

The use of financial instruments may expose the Partnership 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) counterparties fail to purchase the contracted quantities of natural gas or otherwise fail to perform. To the extent that the Partnership engages in hedging activities it may be prevented from realizing the benefits of favorable price changes in the physical market. However, the Partnership is similarly insulated against unfavorable changes in such prices.

As of December 31, 2011, outstanding natural gas swap agreements, NGL swap agreements, swing swap agreements, storage swap agreements and other derivative instruments were a net fair value liability of $2.7 million. The aggregate effect of a hypothetical 10% increase in gas and NGL prices would result in an increase of approximately $2.7 million in the net fair value liability of these contracts as of December 31, 2011 to a net fair value liability of approximately $5.4 million.

Interest Rate Risk

The Partnership is exposed to interest rate risk on its variable rate bank credit facility. At December 31, 2011, the Partnership had $85.0 million outstanding borrowings under this facility. A 1% increase or decrease in interest rates would change our annual interest expense by approximately $0.9 million for the year.

At December 31, 2011 and 2010, the Partnership had total fixed rate debt obligations of $713.4 million and $718.6 million, respectively. The balances at December 31, 2011 and 2010 are substantially related to the Partnership's senior unsecured notes with an interest rate of 8.875%. The fair value of these fixed rate obligations was approximately $882.5 million and $768.3 million as of December 31, 2011 and 2010, respectively. We estimate that a 1% increase or decrease in interest rates would increase or decrease the fair value of the fixed rate debt (the senior unsecured notes) by $23.4 million based on the debt obligations as of December 31, 2011.

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-48 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 our Chief Executive Officer and Chief Financial Officer, 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, our Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of the period covered by this report (December 31, 2011), our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed by us in the reports we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported, within the time period specified in the applicable rules and forms, and that such information is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding disclosure.

(b) Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting that occurred in the three months ended December 31, 2011 that has materially affected, or is reasonably likely to materially affect, our internal control 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***

On February 27, 2012, Crosstex Energy GP, LLC, the general partner of the Partnership, entered into an employment agreement with each of Barry E. Davis, William W. Davis, Joe A. Davis, Michael J. Garberding and Stan Golemon. These employment agreements are substantially similar to one another with certain exceptions, which are set forth in the following discussion. The term of the agreement for Barry E. Davis is three years, for William W. Davis, Joe A. Davis and Michael J. Garberding is two years, and for Stan Golemon is one year and will automatically be extended such that the remaining term of the agreements will not be less than one year. The employment agreements include obligations not to disclose confidential information and also provide for a noncompetition period that will continue after the termination of the employee's employment for one year for Barry E. Davis and for six months for William W. Davis, Joe A. Davis, Michael J. Garberding and Stan Golemon. During the noncompetition period, the employees are generally prohibited from engaging in any business that competes with the Partnership or its affiliates in areas in which the Partnership conducts business as of the date of termination and from soliciting or inducing any of the Company's employees to terminate their employment with the Company. The employment agreements provide a clawback of benefits if the confidential information or noncompetition provisions are breached by a terminated employee following a termination date. In the event of a termination, the terminated employee is required to execute a general release of the company in order to receive any benefits under the employment agreements.

Under these employment agreements, employees receive their annual base salary and are eligible to participate in cash and equity incentive bonus programs based on criteria established by the board of directors of the Company. If the employment of Barry E. Davis, William W. Davis, Joe A. Davis, Michael J. Garberding or Stan Golemon is terminated without cause (as defined in the employment agreement), or is terminated by the employee for good reason (as defined in the employment agreement), or is terminated due to the employee's death or disability, the employment agreement provides that such employee will be paid (i) his or her base salary up to the date of termination, (ii) a pro-rata portion of the target amount of his or her annual bonus up to the date of termination, (iii) an amount equal to the cost to the employee for premium for health insurance continuation under COBRA for an 18-month period, (iv) such other fringe benefits (other than any bonus, severance pay benefit, participation in the company's 401(k) employee benefit plan, or medical insurance benefit) normally provided to employees of the company as earned up to the date of termination, and (v) a lump sum severance amount equal to one year (two years in the case of Barry E. Davis) of the employee's then current base salary, plus one times (two times in the case of Barry E. Davis) the target annual bonus for the year of termination.

The employment agreements provide that in the event of a termination by the Company without cause, or a termination by the employee for good reason, within 120 days prior to or one year following a change of control (as defined in the employment agreements), (i) Barry E. Davis would be paid a lump sum severance amount equal to three years of his then current base salary plus three times the target annual bonus for the year of termination, (ii) William W. Davis, Joe E. Davis and Michael J. Garberding would be paid a lump sum severance amount equal to two years of his then current base salary plus two times the target annual bonus for the year of termination and (iii) Stan Golemon would be paid a lump sum severance amount equal to one year of his then current base salary plus the target annual bonus for the year of termination.

For a summary of the potential payments that may be made to Barry E. Davis, William W. Davis, Joe A. Davis, Michael J. Garberding and Stan Golemon, please see "Item 11. Executive Compensation—Payments Upon Termination or Change of Control" included in the Partnership's Annual Report on Form 10-K for the period ended December 31, 2011. The foregoing summary of the material terms of these employment agreements is qualified by its entirety by reference to the form of employment agreement, a copy of which is filed herewith as Exhibit 10.22.

PART III

Item 10. *Directors, Executive Officers and Corporate Governance*

The following table shows information about the Partnership's executive officers. Executive officers serve until their successors are elected or appointed.

Name	Age	Position with Crosstex Energy GP, LLC
Barry E. Davis(1)	50	President, Chief Executive Officer and Director
William W. Davis(1)	58	Executive Vice President and Chief Operating Officer
Joe A. Davis(1)	51	Executive Vice President, General Counsel and Secretary
Michael J. Garberding	43	Senior Vice President and Chief Financial Officer
Stan Golemon	48	Senior Vice President-Engineering and Operations

(1) Not related.

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 has served as director since our IPO in December 2002. Mr. Davis was President and Chief Operating Officer of Comstock Natural Gas and founder of Ventana Natural Gas, a gas marketing and pipeline company that was purchased by Comstock Natural Gas. Mr. Davis started Ventana Natural Gas in June 1992. Prior to starting Ventana, he was Vice President of Marketing and Project Development for Endevco, Inc. Before joining Endevco, Mr. Davis was employed by Enserch Exploration in the marketing group. Mr. Davis holds a B.B.A. in Finance from Texas Christian University. Mr. Davis also serves as Chairman of the Board for Crosstex Energy, Inc. Mr. Davis is not related to William W. Davis or Joe A. Davis. Mr. Davis' leadership skills and experience in the midstream natural gas industry, among other factors, led the Board to conclude that he should serve as a director.

William W. Davis, Executive Vice President and Chief Operating Officer, joined our predecessor in September 2001, and has over 30 years of finance and accounting experience. Mr. Davis assumed the role of Chief Operating Officer in August 2011. Mr. Davis previously served as our Chief Financial Officer. Prior to joining our predecessor, Mr. Davis held various positions with Sunshine Mining and Refining Company from 1983 to September 2001, including 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 in 1985 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.

Michael J. Garberding, Senior Vice President and Chief Financial Officer joined our general partner in February 2008. Mr. Garberding assumed the role of Chief Financial Officer in August 2011. Mr. Garberding previously led the finance and business development organization for the Partnership. Mr. Garberding has 20 years experience in finance and accounting. From 2002 to 2008, Mr. Garberding held various finance and business development positions at TXU Corporation, including assistant treasurer. In addition, Mr. Garberding worked at Enron North America as a Finance Manager and Arthur Andersen LLP as an Audit Manager. He received his Masters in Business Administration from the University of Michigan in 1999 and his B.B.A. in Accounting from Texas A&M University in 1991.

Stan Golemon, Senior Vice President—Engineering and Operations, joined our general partner in May of 2008. Mr. Golemon has 25 years of experience in engineering, operations, and commercial development in the midstream and exploration and production industries. From 1997 to 2008, Mr. Golemon held various midstream engineering, commercial, and management positions with Union Pacific Resources and its successor company Anadarko Petroleum Corporation including General Manager of Midstream Engineering and Engineering Supervisor. Mr. Golemon also spent 3 years with The Arrington Corporation consulting on sulfur recovery operations and Process Safety Management. Mr. Golemon began his career with ARCO Oil and Gas Company where he worked in plant engineering, onshore facilities engineering, and offshore facilities engineering. Mr. Golemon graduated summa cum laude from Louisiana Tech University in 1985 with a Bachelor of Science degree in Chemical Engineering.

Code of Ethics

We adopted a Code of Business Conduct and Ethics (the "Code of Ethics") applicable to all of our employees, officers, and directors, with regard to company-related activities. The Code of Ethics incorporates guidelines designed to deter wrongdoing and to promote honest and ethical conduct and compliance with applicable laws and regulations. The Code of Ethics also incorporates our expectations of our employees that enable us to provide accurate and timely disclosure in our filings with the Securities and Exchange Commission and other public communications. A copy of the Code of Ethics is available to any person, free of charge, at our web site: www.crosstexenergy.com. If any substantive amendments are made to the Code of Ethics or if we grant any waiver, including any implicit waiver, from a provision of the Code of Ethics to any of our executive officers and directors, we will disclose the nature of such amendment or waiver on our web site.

Other

The sections entitled "Proposal One: Election of Directors," "Additional Information Regarding the Board of Directors," "Section 16(a) Beneficial Ownership Reporting Compliance," and "Stockholder Proposals and Other Matters" that will appear in our proxy statement for the 2012 annual meeting of stockholders, which we expect to file with the Securities and Exchange Commission within 120 days after December 31, 2011 (the "2012 Proxy Statement"), will set forth certain information with respect to our directors and with respect to reporting under Section 16(a) of the Securities Exchange Act of 1934, and are incorporated herein by reference.

Item 11. *Executive Compensation*

The section entitled "Executive Compensation" that will appear in the 2012 Proxy Statement will set forth certain information with respect to the compensation of our management, and is incorporated herein by reference

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

The sections entitled "Equity Compensation Plans" and "Security Ownership of Certain Beneficial Owners and Management" that appears in the 2012 Proxy Statement will set forth certain information with respect to securities authorized for issuance under equity compensation plans and the ownership of our voting securities and equity securities and are incorporated herein by reference.

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

The sections entitled "Certain Relationships and Related Party Transactions" and "Additional Information Regarding the Board of Directors" that will appear in the 2012 Proxy Statement will set forth certain information with respect to certain relationships and related party transactions, and are incorporated herein by reference.

Item 14. *Principal Accounting Fees and Services*

The section entitled "Fees Paid to Independent Public Accounting Firm" that will appear in the 2012 Proxy Statement will set forth certain information with respect to accounting fees and services, and is incorporated herein by reference.

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) Schedule I—Parent Company Statements on page F-45 and Schedule II—Valuation and Qualifying Accounts on page F-48.

(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
2.1***	—	Partnership Interest Purchase and Sale Agreement, dated as of June 9, 2009, among Crosstex Energy Services, L.P., Crosstex Energy Services GP, LLC, Crosstex CCNG Gathering, Ltd., Crosstex CCNG Transmission Ltd., Crosstex Gulf Coast Transmission Ltd., Crosstex Mississippi Pipeline, L.P., Crosstex Mississippi Gathering, L.P., Crosstex Mississippi Industrial Gas Sales, L.P., Crosstex Alabama Gathering System, L.P., Crosstex Midstream Services, L.P., Javelina Marketing Company Ltd., Javelina NGL Pipeline Ltd. and Southcross Energy LLC (incorporated by reference to Exhibit 2.1 to Crosstex Energy, L.P.'s Current Report on Form 8-K dated June 9, 2009, filed with the Commission on June 11, 2009, file No. 000-50067).
2.2***	—	Partnership Interest Purchase and Sale Agreement, dated as of August 28, 2009, among Crosstex Energy Services, L.P., Crosstex Energy Services GP, LLC, Crosstex Treating Services, L.P. and KM Treating GP LLC (incorporated by reference to Exhibit 2.1 to Crosstex Energy, L.P.'s Current Report on Form 8-K dated August 28, 2009, filed with the Commission on September 3, 2009, file No. 000-50067).
3.1	—	Amended and Restated Certificate of Incorporation of Crosstex Energy, Inc. (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated October 26, 2006, filed with the Commission on October 31, 2006, file No. 000-50536).
3.2	—	Third Amended and Restated Bylaws of Crosstex Energy, Inc. (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated March 22, 2006, filed with the Commission on March 28, 2006, file No. 000-50536).
3.3	—	Certificate of Limited Partnership of Crosstex Energy, L.P. (incorporated by reference to Exhibit 3.1 to Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-97779).
3.4	—	Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of March 23, 2007 (incorporated by reference to Exhibit 3.1 to Crosstex Energy, L.P.'s Current Report on Form 8-K dated March 23, 2007, filed with the Commission on March 27, 2007, file No. 000-50067).
3.5	—	Amendment No. 1 to Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated December 20, 2007 (incorporated by reference to Exhibit 3.1 to Crosstex Energy, L.P.'s Current Report on Form 8-K dated December 20, 2007, filed with the Commission on December 21, 2007, file No. 000-50067).

Number		Description
3.6	—	Amendment No. 2 to Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P. (incorporated by reference to Exhibit 3.1 to Crosstex Energy, L.P.'s Current Report on Form 8-K dated March 27, 2008, filed with the Commission on March 28, 2008, file No. 000-50067).
3.7	—	Amendment No. 3 to Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of January 19, 2010 (incorporated by reference to Exhibit 3.1 to Crosstex Energy, L.P.'s Current Report on Form 8-K dated January 19, 2010, filed with the Commission on January 22, 2010, file No. 000-50067).
3.8	—	Certificate of Limited Partnership of Crosstex Energy Services, L.P. (incorporated by reference to Exhibit 3.3 to Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-97779).
3.9	—	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 Crosstex Energy, L.P.'s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004, file No. 000-50067).
3.10	—	Certificate of Formation of Crosstex Energy GP, LLC (incorporated by reference to Exhibit 3.7 to Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-97779).
3.11	—	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 Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-97779).
3.12	—	Amendment No. 1 to Amended and Restated Limited Liability Company Agreement of Crosstex Energy GP, LLC, dated as of January 19, 2010 (incorporated by reference to Exhibit 3.2 to Crosstex Energy, L.P.'s Current Report on Form 8-K dated January 19, 2010, filed with the Commission on January 22, 2010, file No. 000-50067).
4.1	—	Specimen Certificate representing shares of common stock (incorporated by reference from Exhibit 4.1 to our Registration Statement on Form S-1, file No. 333-110095).
4.2	—	Registration Rights Agreement, dated as of January 19, 2010, by and among Crosstex Energy, L.P. and GSO Crosstex Holdings LLC (incorporated by reference to Exhibit 4.1 to Crosstex Energy, L.P.'s Current Report on Form 8-K dated January 19, 2010, filed with the Commission on January 22, 2010, file No. 000-50067).
4.3	—	Indenture, dated as of February 10, 2010, by and among Crosstex Energy, L.P., Crosstex Energy Finance Corporation, the Guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to Crosstex Energy, L.P.'s Current Report on Form 8-K dated February 10, 2010, filed with the Commission on February 16, 2010, file No. 000-50067).
4.4	—	Supplemental Indenture, dated as of July 11, 2011, to the Indenture governing the Issuers' 8.875% senior unsecured notes due 2018, dated as of February 10, 2010, by and among Crosstex Energy, L.P., Crosstex Energy Finance Corporation, the Guarantors names therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated July 11, 2011, filed with the Commission on July 12, 2011, file No. 000-50067).

Number		Description
4.5	—	Supplemental Indenture, dated as of January 24, 2012, to the Indenture governing the Issuers' 8.875% senior unsecured notes due 2018, dated as of February 10, 2010, by and among Crosstex Energy, L.P., Crosstex Energy Finance Corporation, the Guarantors named therein and Well Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated January 24, 2012, filed with the Commission on January 25, 2012, file No. 000-50067).
4.6	—	Registration Rights Agreement, dated as of February 10, 2010, by and among Crosstex Energy, L.P., Crosstex Energy Finance Corporation, the Guarantors named therein and the Initial Purchasers named therein (incorporated by reference to Exhibit 4.2 to Crosstex Energy, L.P.'s Current Report on Form 8-K dated February 10, 2010, filed with the Commission on February 16, 2010, file No. 000-50067).
4.7	—	Registration Rights Agreement, dated as of January 19, 2010, by and among Crosstex Energy, L.P. and GSO Crosstex Holdings LLC (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated January 19, 2010, filed with the Commission on January 22, 2010, file No. 000-50067).
10.1†	—	Crosstex Energy, Inc. Amended and Restated Long-Term Incentive Plan effective as of September 6, 2006 (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated October 26, 2006, filed with the Commission on October 31, 2006, file No. 000-50536).
10.2†	—	Crosstex Energy GP, LLC Amended and Restated Long-Term Incentive Plan, dated March 17, 2009 (incorporated by reference to Exhibit 10.3 to Crosstex Energy, L.P.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2009, file No. 000-50067).
10.3†	—	Crosstex Energy, Inc. 2009 Long-Term Incentive Plan, effective March 17, 2009 (incorporated by reference to Exhibit 10.3 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2009, file No. 000-50536).
10.4	—	Omnibus Agreement, dated December 17, 2002, among Crosstex Energy, L.P. and certain other parties (incorporated by reference to Exhibit 10.5 to Crosstex Energy, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2002, file No. 000-50067).
10.5†	—	Form of Employment Agreement (incorporated by reference to Exhibit 10.6 to Crosstex Energy, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2002, file No. 000-50067).
10.6†	—	Form of Severance Agreement (incorporated by reference to Exhibit 10.6 to Crosstex Energy, L.P.'s Annual Report on Form 10K for the year ended December 31, 2009, file No. 000-50067).
10.7†	—	Form of Performance Unit Agreement (incorporated by reference to Exhibit 10.1 to Crosstex Energy, L.P.'s Current Report on Form 8-K dated June 27, 2007, filed with the Commission on July 3, 2007, file No. 000-50067).
10.8†	—	Form of Performance Share Agreement (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated June 27, 2007, filed with the Commission on July 3, 2007, file No. 000-50536).
10.9†	—	Form of Restricted Stock Agreement (incorporated by reference to Exhibit 10.9 to our Annual Report on Form 10-K for the year ended December 31,2009, file No. 000-50067).

Number		Description
10.10†	—	Form of Restricted Unit Agreement (incorporated by reference to Exhibit 10.9 to Crosstex Energy, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2009, file No. 000-50067).
10.11†	—	Form of Indemnity Agreement (incorporated by reference to Exhibit 10.2 to our Annual Report on Form 10-K for the year ended December 31, 2003, file No. 000-50536).
10.12	—	Board Representation Agreement, dated as of January 19, 2010, by and among Crosstex Energy GP, LLC, Crosstex Energy GP, L.P., Crosstex Energy, L.P., Crosstex Energy, Inc. and GSO Crosstex Holdings LLC (incorporated by reference to Exhibit 10.1 to Crosstex Energy, L.P.'s Current Report on Form 8-K dated January 19, 2010, filed with the Commission on January 22, 2010, file No. 000-50067).
10.13	—	Purchase Agreement, dated as of February 3, 2010, by and among Crosstex Energy, L.P., Crosstex Energy Finance Corporation, the Guarantors named therein and the Initial Purchasers named therein (incorporated by reference to Exhibit 10.1 to Crosstex Energy, L.P.'s Current Report on Form 8-K dated February 3, 2010, filed with the Commission on February 5, 2010, file No. 000-50067).
10.14	—	Amended and Restated Credit Agreement, dated as of February 10, 2010, by and among Crosstex Energy, L.P., Bank of America, N.A., as Administrative Agent and L/C Issuer thereunder, and the other lenders party thereto (incorporated by reference to Exhibit 10.1 to Crosstex Energy, L.P.'s Current Report on Form 8-K dated February 10, 2010, filed with the Commission on February 16, 2010, file No. 000-50067).
10.15	—	Series A Convertible Preferred Unit Purchase Agreement, dated as of January 6, 2010, by and between Crosstex Energy, L.P. and GSO Crosstex Holding LLC (incorporated by reference to Exhibit 10.1 to Crosstex Energy, L.P.'s Current Report on Form 8-K dated January 6, 2010, filed with the Commission on February 11, 2010, file No. 000-50067).
10.16	—	Agreement Regarding 2003 Registration Statement and Waiver and Termination of Stockholders' Agreement, dated October 27, 2003 (incorporated by reference from Exhibit 10.4 to our Annual Report on Form 10-K for the year ended December 31, 2003, file No. 000-50536).
10.17	—	Registration Rights Agreement, dated December 31, 2003 (incorporated by reference from Exhibit 10.6 to our Annual Report on Form 10-K for the year ended December 31, 2003, file No. 000-50536).
10.18	—	First Amendment to Amended and Restated Credit Agreement dated as of May 2, 2011, by and among Crosstex Energy, L.P., Bank of America, N.A., as Administrative Agent and L/C Issuer, and the other lenders party thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated May 2, 2011, filed with the Commission on May 3, 2011, file No. 000-50067).
10.19	—	Second Amendment to Amended and Restated Credit Agreement dated as of July 11, 2011, by and among Crosstex Energy, L.P., Bank of America, N.A., as Administrative Agent and L/C Issuer, and the other lenders party thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated July 11, 2011, filed with the Commission on July 12, 2011, file No. 000-50067).

Number		Description
10.20	—	Third Amendment to Amended and Restated Credit Agreement dated as of January 24, 2012, by and among Crosstex Energy, L.P., Bank of America, N.A., as Administrative Agent and L/C Issuer, and the other lenders party thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated January 24, 2012, filed with the Commission on January 25, 2012, file No. 000-50067).
10.21†	—	Crosstex Energy Services, L.P. Severance Pay Plan (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K July 1, 2011, filed with the Commission on July 1, 2011, file No. 000-50067).
10.22†	—	Form of Employment Agreement (incorporated by reference to Exhibit 10.20 to Crosstex Energy, L.P.'s Annual Report on Form 10-k for the year ended December 31, 2011, file No. 000-50067).
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.
101**	—	The following financial information from Crosstex Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2011, formatted in XBRL (eXtensible Business Reporting Language): (i) Consolidated Statements of Operations for the years ended December 31, 2011, 2010, and 2009, (ii) Consolidated Balance Sheets as of December 31, 2011, and 2010 , (iii) Consolidated Statements of Cash Flows for the years ended December 31, 2011, 2010, and 2009, (iv) Consolidated Statements of Comprehensive Income for the years ended December 31, 2011, 2010, and 2009, (v) Consolidated Statements of Changes in Stockholders' Equity for the years ended December 31, 2011, 2010, and 2009 and (vi) the Notes to Consolidated Financial Statements.

* Filed herewith.

** Furnished herewith.

*** In accordance with the instructions to item 601(b)(2) of Regulation S-K, the exhibits and schedules to Exhibits 2.1 and 2.2 are not filed herewith. The agreements identify such exhibits and schedules, including the general nature of their content. We undertake to provide such exhibits and schedules to the Commission upon request.

† As required by Item 15(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 2012.

CROSSTEX ENERGY, INC.

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 by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ BARRY E. DAVIS Barry E. Davis	President, Chief Executive Officer and Chairman of the Board (Principal Executive Officer)	February 28, 2012
/s/ LELDON E. ECHOLS Leldon E. Echols	Director	February 28, 2012
/s/ JAMES C. CRAIN James C. Crain	Director	February 28, 2012
/s/ BRYAN H. LAWRENCE Bryan H. Lawrence	Director	February 28, 2012
/s/ SHELDON B. LUBAR Sheldon B. Lubar	Director	February 28, 2012
/s/ CECIL E. MARTIN Cecil E. Martin	Director	February 28, 2012
/s/ ROBERT F. MURCHISON Robert F. Murchison	Director	February 28, 2012
/s/ MICHAEL J. GARBERDING Michael J. Garberding	Senior Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	February 28, 2012

(This page has been left blank intentionally.)

INDEX TO FINANCIAL STATEMENTS

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of Crosstex Energy Inc. 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, Inc (the "Company"). As defined by the Securities and Exchange Commission (Rule 13a-15(f) under the Securities Exchange Act of 1934, as amended), internal control over financial reporting is a process designed by, or under the supervision of Crosstex Energy Inc.'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 Company'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 Company's transactions and dispositions of the Company'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 Company's management and directors; 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 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 Company's annual consolidated financial statements, management has undertaken an assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2011, 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 Company'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, 2011, the Company'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 Company's consolidated financial statements included in this report, has issued an attestation report on the Company's 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

To the Board of Directors and the Stockholders of
Crosstex Energy, Inc:

We have audited the accompanying consolidated balance sheets of Crosstex Energy, Inc. (a Delaware corporation) and subsidiaries (the Company) as of December 31, 2011 and 2010 and the related consolidated statements of operations, comprehensive income (loss), changes in stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2011. In connection with our audits of the consolidated financial statements, we also have audited the accompanying financial statement schedules. These consolidated financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedules 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, Inc. and subsidiaries as of December 31, 2011 and 2010 and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2011, in conformity with U.S. generally accepted accounting principles. Also in our opinion, the related financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2011, 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, 2012 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

Dallas, Texas
February 28, 2012

Report of Independent Registered Public Accounting Firm

To the Board of Directors and the Stockholders of
Crosstex Energy, Inc:

We have audited Crosstex Energy, Inc. and subsidiaries' (the Company) internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company'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, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company'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, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included 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, Crosstex Energy Inc. and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of the Company as of December 31, 2011 and 2010, and the related consolidated statements of operations, changes in stockholders' equity, comprehensive income (loss), and cash flows for each of the years in the three-year period ended December 31, 2011, and our report dated February 28, 2012 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Dallas, Texas
February 28, 2012

CROSSTEX ENERGY, INC.

Consolidated Balance Sheets

	December 31, 2011	December 31, 2010
	(In thousands, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 30,343	$ 22,780
Accounts receivable:		
Trade, net of allowance for bad debts of $405 and $163, respectively	22,680	16,217
Accrued revenues	140,023	190,726
Imbalances	1,658	2,920
Other	1,516	135
Fair value of derivative assets	2,867	5,523
Natural gas and natural gas liquids, prepaid expenses and other	9,965	9,780
Total current assets	209,052	248,081
Property and equipment:		
Transmission assets	384,959	383,651
Gathering systems	656,407	623,451
Gas plants	494,365	461,865
Other property and equipment	58,465	56,231
Construction in process	55,467	20,709
Total property and equipment	1,649,663	1,545,907
Accumulated depreciation	(406,773)	(329,741)
Total property and equipment, net	1,242,890	1,216,166
Fair value of derivative assets	—	1,169
Intangible assets, net of accumulated amortization of $199,248 and $151,735, respectively	451,462	498,975
Investment in limited liability company	35,000	—
Other assets, net	24,212	26,712
Total assets	$1,962,616	$1,991,103
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Drafts payable	6,005	151
Accounts payable	14,196	15,988
Accrued gas purchases	106,233	160,909
Accrued imbalances payable	2,348	1,889
Fair value of derivative liabilities	5,587	7,980
Current portion of long-term debt	—	7,058
Accrued interest	24,918	24,843
Other current liabilities	66,567	42,044
Total current liabilities	225,854	260,862
Long-term debt	798,409	711,512
Other long-term liabilities	23,919	26,879
Deferred tax liability	85,187	89,216
Fair value of derivative liabilities	—	1,156
Commitments and contingencies	—	—
Stockholders' equity:		
Common stock (150,000,000 shares authorized, $.01 par value, 47,194,023 and 46,894,859 issued and outstanding in 2011 and 2010, respectively)	471	468
Additional paid-in capital	244,211	242,390
Accumulated deficit	(82,177)	(58,298)
Accumulated other comprehensive loss	(85)	(145)
Total Crosstex Energy, Inc. stockholders' equity	162,420	184,415
Interest of non-controlling partners in the Partnership	666,827	717,063
Total stockholders' equity	829,247	901,478
Total liabilities and stockholders' equity	$1,962,616	$1,991,103

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, INC.

Consolidated Statements of Operations

	Years ended December 31,		
	2011	2010	2009
	(In thousands, except per unit data)		
Revenues:			
Midstream	$2,013,942	$1,792,676	$1,583,551
Total revenues	2,013,942	1,792,676	1,583,551
Operating costs and expenses:			
Purchased gas and NGLs	1,638,777	1,454,376	1,272,329
Operating expenses	111,778	105,060	110,394
General and administrative	55,516	51,172	62,491
(Gain) loss on sale of property	264	(13,881)	(666)
(Gain) loss on derivatives	7,776	9,100	(2,994)
Impairments	—	1,311	2,894
Depreciation and amortization	125,358	111,625	119,162
Total operating costs and expenses	1,939,469	1,718,763	1,563,610
Operating income	74,473	73,913	19,941
Other income (expense):			
Interest expense, net of interest income	(79,227)	(87,028)	(95,078)
Loss on extinguishment of debt	—	(14,713)	(4,669)
Other income	707	294	1,449
Total other expense	(78,520)	(101,447)	(98,298)
Loss from continuing operations before income taxes	(4,047)	(27,534)	(78,357)
Income tax benefit from continuing operations	2,768	6,021	6,020
Loss from continuing operations	(1,279)	(21,513)	(72,337)
Discontinued operations:			
Loss from discontinued operations, net of tax of $0, $0 and $255, respectively	—	—	(1,519)
Gain on sale of discontinued operations, net of tax of $0, $0 and $(23,735), respectively	—	—	159,961
Discontinued operations, net of tax	—	—	158,442
Net income (loss)	(1,279)	(21,513)	86,105
Less: Interest of non-controlling partners in the Partnership's net income (loss):			
Interest of non-controlling partners in the Partnership's continuing operations	4,728	(9,862)	(48,069)
Interest of non-controlling partners in the Partnership's discontinued operations	—	—	(1,137)
Interest of non-controlling partners in the Partnership's gain on sale of discontinued operations	—	—	119,669
Total interest of non-controlling partners in the Partnership's net income (loss)	4,728	(9,862)	70,463
Net income (loss) attributable to Crosstex Energy, Inc.	$ (6,007)	$ (11,651)	$ 15,642
Net income (loss) per common share:			
Basic	$ (0.12)	$ (0.24)	$ 0.33
Diluted	$ (0.12)	$ (0.24)	$ 0.33
Weighted -average shares outstanding:			
Basic	47,150	46,732	46,476
Diluted	47,150	46,732	46,535
Dividend per share:			
Common	$ 0.37	$ 0.07	$ 0.09
Amount attributable to Crosstex Energy, Inc. common shareholders:			
Loss from continuing operations, net of tax and non-controlling interest	$ (6,007)	$ (11,651)	$ (24,267)
Income (loss) from discontinued operations, net of tax and non-controlling interest	—	—	(383)
Gain on sale of discontinued operations, net of tax and non-controlling interest	—	—	40,292
Net income (loss) attributable to Crosstex Energy, Inc.	$ (6,007)	$ (11,651)	$ 15,642

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, INC.

Consolidated Statements of Comprehensive Income (Loss)

	Years Ended December 31,		
	2011	2010	2009
		(In thousands)	
Net income (loss)	$(1,279)	$(21,513)	$86,105
Change in non-controlling interest's portion of accumulated other comprehensive income due to issuance of units by the Partnership, net of taxes of $0, $68 and $0, respectively	—	115	—
Hedging gains or losses reclassified to earnings, net of taxes of $195, $208 and $(324), respectively	1,769	1,877	(2,087)
Adjustment in fair value of derivatives, net of taxes of $(159), $(26) and $(406), respectively	(1,446)	(249)	(2,964)
Comprehensive income (loss)	(956)	(19,770)	81,054
Comprehensive income (loss) attributable to non-controlling interest	4,991	(8,542)	66,650
Comprehensive income (loss) attributable to Crosstex Energy, Inc.	$(5,947)	$(11,228)	$14,404

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, INC.

Consolidated Statements of Changes in Stockholders' Equity

Years ended December 31, 2011, 2010 and 2009

	Common Stock Shares	Common Stock Amount	Additional Paid-In Capital	Retained Earnings (Deficit)	Accumulated Other Comprehensive Income (loss)	Non-Controlling Interest	Total Stockholders' Equity
			(In thousands)				
Balance, December 31, 2008	46,342	$464	$268,988	$(54,693)	$ 670	$522,961	$738,390
Offering costs	—	—	(42)	—	—	—	(42)
Conversion of restricted stock for common, net of shares withheld for taxes	182	—	(354)	—	—	—	(354)
Stock-based compensation	—	—	3,077	—	—	5,778	8,855
Common dividends	—	—	—	(4,228)	—	—	(4,228)
Net income (loss)	—	—	—	15,642	—	70,463	86,105
Hedging gains or losses reclassified to earnings	—	—	—	—	(550)	(1,537)	(2,087)
Adjustment in fair value of derivatives	—	—	—	—	(688)	(2,276)	(2,964)
Distribution to non-controlling interest	—	—	—	—	—	(7,765)	(7,765)
Balance, December 31, 2009	46,524	464	271,669	(43,279)	(568)	587,624	815,910
Issuance of units by the Partnership to non-controlling interest	—	—	—	—	—	120,786	120,786
Conversion of restricted stock for common, net of shares withheld for taxes	370	4	(709)	—	—	—	(705)
Change in equity due to issuance of units by the Partnership	—	—	(32,769)	—	115	32,586	(68)
Stock-based compensation	—	—	4,199	—	—	5,370	9,569
Common dividends	—	—	—	(3,368)	—	—	(3,368)
Net income	—	—	—	(11,651)	—	(9,862)	(21,513)
Hedging gains or losses reclassified to earnings	—	—	—	—	353	1,524	1,877
Adjustment in fair value of derivatives	—	—	—	—	(45)	(204)	(249)
Non-controlling partner's impact of conversion of restricted units and option exercises	—	—	—	—	—	(1,768)	(1,768)
Distribution to non-controlling interest	—	—	—	—	—	(18,993)	(18,993)
Balance, December 31, 2010	46,894	468	242,390	(58,298)	(145)	717,063	901,478
Conversion of restricted stock for common, net of shares withheld for taxes	300	3	(1,071)	—	—	—	(1,068)
Change in equity due to issuance of units by the Partnership	—	—	(476)	—	—	—	(476)
Stock-based compensation	—	—	3,368	—	—	4,188	7,556
Common dividends	—	—	—	(17,872)	—	—	(17,872)
Net income (loss)	—	—	—	(6,007)	—	4,728	(1,279)
Hedging gains or losses reclassified to earnings	—	—	—	—	330	1,439	1,769
Adjustment in fair value of derivatives	—	—	—	—	(270)	(1,176)	(1,446)
Non-controlling partner's impact of conversion of restricted units and option exercises	—	—	—	—	—	(1,206)	(1,206)
Distribution to non-controlling interest	—	—	—	—	—	(58,209)	(58,209)
Balance, December 31, 2011	47,194	$471	$244,211	$(82,177)	$ (85)	$666,827	$829,247

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, INC.

Consolidated Statements of Cash Flows

	Years Ended December 31,		
	2011	2010	2009
		(In thousands)	
Cash flows from operating activities:			
Net income (loss)	$ (1,279)	$ (21,513)	$ 86,105
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization	125,358	111,625	129,812
Non-cash stock-based compensation	7,556	9,569	8,855
(Gain) loss on sale of property	264	(13,881)	(184,412)
Impairments	—	1,311	2,894
Deferred tax (benefit) expense	(4,540)	(7,538)	15,229
Derivatives mark to market interest rate settlement	—	(24,160)	—
Non-cash portion of derivatives loss	761	1,136	2,184
Non-cash portion of loss on debt extinguishment	—	5,396	4,669
Interest paid-in-kind	—	(11,558)	10,134
Amortization of debt issue costs	6,462	6,680	11,812
Amortization of discount on notes	1,897	1,686	—
Changes in assets and liabilities:			
Accounts receivable, accrued revenue and other	44,121	4,665	127,981
Natural gas and natural gas liquids, prepaid expenses and other	(1,507)	2,376	(5,287)
Accounts payable, accrued gas purchases and other accrued liabilities	(37,800)	18,996	(131,126)
Net cash provided by operating activities	141,293	84,790	78,850
Cash flows from investing activities:			
Additions to property and equipment	(97,572)	(48,191)	(101,370)
Insurance recoveries on property and equipment	—	2,599	12,458
Acquisitions and asset purchases	—	—	(35,142)
Proceeds from sale of property	478	60,230	503,928
Investment in limited liability company	(35,000)	—	—
Net cash provided by (used in) investing activities	(132,094)	14,638	379,874
Cash flows from financing activities:			
Proceeds from borrowings	471,250	997,412	632,807
Payments on borrowings	(393,308)	(1,144,705)	(1,050,389)
Proceeds from capital lease obligations	—	—	1,695
Payments on capital lease obligations	(3,122)	(2,385)	(2,414)
Increase (decrease) in drafts payable	5,854	(5,063)	(16,300)
Debt refinancing costs	(3,954)	(28,561)	(15,031)
Distributions to non-controlling partners in the Partnership	(58,209)	(18,993)	(7,601)
Common dividends paid	(17,872)	(3,368)	(4,228)
Conversion of restricted units, net of units withheld for taxes	(1,798)	(2,659)	(232)
Conversion of restricted stock, net of shares withheld for taxes	(1,068)	(705)	(354)
Proceeds from issuance of Partnership units	—	120,786	—
Proceeds from exercise of Partnership unit options	591	890	67
Net cash used in financing activities	(1,636)	(87,351)	(461,980)
Net increase (decrease) in cash and cash equivalents	7,563	12,077	(3,256)
Cash and cash equivalents, beginning of period	22,780	10,703	13,959
Cash and cash equivalents, end of period	$ 30,343	$ 22,780	$ 10,703
Cash paid for interest	$ 71,950	$ 66,081	$ 91,454
Cash paid (refunded) for income taxes	$ 1,104	$ (33)	$ 926

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, INC.

Notes to Consolidated Financial Statements

December 31, 2011 and 2010

(1) Organization and Summary of Significant Agreements

(a) Description of Business

Crosstex Energy, Inc., a Delaware corporation formed on April 28, 2000, is engaged, through its subsidiaries, in the gathering, transmission, processing and marketing of natural gas and natural gas liquids (NGLs). The Company connects the wells of natural gas producers in the geographic areas of its gathering systems in order to gather for a fee or purchase the gas production, processes natural gas for the removal of NGLs, transports natural gas and NGLs and ultimately provides natural gas and NGLs to a variety of markets. In addition, the Company purchases natural gas and NGLs from producers not connected to its gathering systems for resale and markets natural gas and NGLs on behalf of producers for a fee. The Company recently added crude oil terminal facilities in south Louisiana to provide access for crude oil producers to the premium markets in this area.

(b) Organization

On July 12, 2002, the Company formed Crosstex Energy L.P. (herein referred to as the Partnership or CELP), a Delaware limited partnership. Crosstex Energy GP, LLC, a wholly owned subsidiary of the Company, is the general partner of the Partnership. The Company owns 16,414,830 common units in the Partnership through its wholly owned subsidiaries on December 31, 2011, which represented 25.0% of the limited partner interests in the Partnership.

(c) Basis of Presentation

The accompanying consolidated financial statements include the assets, liabilities, and results of operations of the Company and its majority owned subsidiaries, including the Partnership. The Partnership proportionately consolidates its undivided 50.0% interest in a gas processing plant invested in by the Partnership in July 2011, and its undivided 64.29% interest in a gas plant acquired by the Partnership in November 2005 (23.85%), in May 2006 (35.42%) and June 2011 (5.02%). In accordance with FASB ASC 810-10-05-8, the Company consolidates its joint venture interest in Crosstex DC Gathering, J.V. (CDC). The consolidated operations are hereafter referred to herein collectively as the "Company." 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 Company 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 Company considers all highly liquid investments with an original maturity of three months or less to be cash equivalents.

(2) Significant Accounting Policies (Continued)

(c) Natural Gas and Natural Gas Liquids Inventory

Inventories of products consist of natural gas and NGLs. The Company 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, NGL pipelines, natural gas processing plants and NGL fractionation plants. Gas required to maintain pipeline minimum pressures is capitalized and classified as property, plant and equipment. 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 $0.9 million, $0.1 million and $1.1 million were capitalized for the years ended December 31, 2011, 2010 and 2009, respectively.

Depreciation is provided using the straight-line method based on the estimated useful life of each asset, as follows:

	Useful Lives
Transmission assets	20 - 30 years
Gathering systems	15 - 20 years
Gas processing plants	20 years
Other property and equipment	3 - 15 years

Depreciation expense of $77.8 million, $75.7 million and $82.5 million was recorded for the years ended December 31, 2011, 2010 and 2009, respectively. Depreciation expense also includes the amortization of assets classified as capital lease assets.

FASB ASC 360-10-05-4 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 Company compares the net book value of the asset to the undiscounted expected future net cash flows. If an 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.

When determining whether impairment of one of our long-lived assets has occurred, we must estimate the undiscounted cash flows attributable to the asset. The Company'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.

(2) Significant Accounting Policies (Continued)

The Company recorded impairments to long-lived assets of $1.3 million and $2.9 million during the years ended December 31, 2010 and 2009, respectively. See Note 4(c) for further details on the long-lived assets impaired.

(e) Intangible Assets

Intangible assets consist of customer relationships and the value of the dedicated and non-dedicated acreage attributable to pipeline, gathering and processing systems. Intangible assets associated with customer relationships 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 dedicated and non-dedicated acreage attributable to pipeline, gathering and processing systems are being amortized using the units of throughput method of amortization.

The following table represents the Partnership's total purchased intangible assets at years ended December 31, 2011 and 2010 (in thousands):

	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
2011			
Customer relationships	$255,058	$(101,762)	$153,296
Dedicated and non-dedicated acreage	395,652	(97,486)	298,166
Total	$650,710	$(199,248)	$451,462
2010			
Customer relationships	$255,058	$ (86,524)	$168,534
Dedicated and non-dedicated acreage	395,652	(65,211)	330,441
Total	$650,710	$(151,735)	$498,975

The weighted average amortization period for intangible assets is 18.0 years. Amortization expense for intangibles was approximately $47.5 million, $35.9 million and $36.6 million for the years ended December 31, 2011, 2010 and 2009, respectively.

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

2012	$ 44,995
2013	41,786
2014	40,578
2015	41,296
2016	41,880
Thereafter	240,927
Total	$451,462

(2) Significant Accounting Policies (Continued)

(f) Investment in Limited Partnership

The Partnership owns a majority interest in Crosstex Denton County Joint Venture (CDC) and consolidates its investment in CDC pursuant to FASB ASC 810-10-05-8. The Partnership manages the business affairs of CDC, which owns a small gas gathering system in north Texas. The other joint venture partner (the CDC partner) is an unrelated third party who owns and operates a natural gas field located in Denton County, Texas.

(g) Investment in Limited Liability Company

On June 22, 2011, the Partnership entered into a limited liability agreement with Howard Energy Partners ("HEP") for an initial capital contribution of $35.0 million in exchange for an individual ownership interest in HEP of approximately 35.0%. In addition to the Partnership's contribution, an unrelated party also provided a capital contribution of $35.0 million for a 35.0% ownership interest in HEP with HEP management and a few private investors owning the remaining 30.0% interest. HEP owns assets and provides midstream and construction services to Eagle Ford Shale producers in south Texas. This investment in HEP is accounted for under the equity method of accounting and is reflected on the balance sheet as "Investment in limited liability company." Per the terms of the agreement, the Partnership will not recognize any income from this investment until HEP's income exceeds approximately $9.9 million on an inception to date basis due to preferred interests owned by HEP management. If HEP has losses on an inception to date basis, the Partnership will recognize 39.3% of the losses.

(h) Other Assets

Unamortized debt issuance costs totaling $24.2 million and $26.7 million as of December 31, 2011 and 2010, respectively, are included in other assets, net. Debt issuance costs are amortized into interest expense using the straight-line method over the terms of the debt.

(i) Gas Imbalance Accounting

Quantities of natural gas and NGLs 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 or NGLs. The Company had imbalance payables of $2.3 million and $1.9 million at December 31, 2011 and 2010, respectively, which approximate the fair value of these imbalances. The Company had imbalance receivables of $1.7 million and $2.9 million at December 31, 2011 and 2010, which are carried at the lower of cost or market value.

(j) Asset Retirement Obligations

FASB ASC 410-20-25-16 was issued in March 2005, which became effective at December 31, 2005. FASB ASC 410-20-25-16 clarifies that the term "conditional asset retirement obligation" as used in FASB ASC 410-20, 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, FASB ASC 410-20-25-16 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

(2) Significant Accounting Policies (Continued)

exists about the timing and/or method of settlement. FASB ASC 410-20-25-16 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation under FASB ASC 410-20. The Company did not provide any asset retirement obligations as of December 31, 2011 and 2010 because it does not have sufficient information as set forth in FASB ASC 410-20-25-16 to reasonably estimate such obligations, and the Company has no current intention of discontinuing use of any significant assets.

(k) Revenue Recognition

The Company recognizes revenue for sales or services at the time the natural gas or NGLs are delivered or at the time the service is performed. The Company generally accrues one month 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. Purchase and sale arrangements are generally reported in revenues and costs on a gross basis in the consolidated statement of operations in accordance with FASB ASC 605-45-45-1. Except for fee based arrangements, the Partnership acts as the principal in these purchase and sale transactions, has the risk and reward of ownership as evidenced by title transfer, schedules the transportation and assumes credit risk. The Partnership conducts "off-system" gas marketing operations as a service to producers on systems that it does not own. It refers to these activities as part of 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 revenue and cost of sales for these activities are included in revenue on a net basis in the consolidated statement of operations.

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

(l) Derivatives

The Partnership uses derivatives to hedge against changes in cash flows related to product price, as opposed to their use for trading purposes. FASB ASC 815 requires that all derivatives be recorded on the balance sheet at fair value. It generally determines the fair value of futures contracts and swap contracts based on the difference between the derivative's fixed contract price and the underlying market price at the determination date. The asset or liability related to the derivative instruments is recorded on the balance sheet in fair value of derivative assets or liabilities.

Realized and unrealized gains and losses on commodity related derivatives that are not designated as hedges, as well as the ineffective portion of hedge derivatives, are recorded as gain or loss on derivatives in the consolidated statement of operations. Realized and unrealized gains and losses on interest rate derivatives that are not designated as hedges are included in interest expense in the consolidated statement of operations. Unrealized gains and losses on effective cash flow hedge derivatives are recorded as a component of accumulated other comprehensive income. When the hedged transaction occurs, the realized gain or loss on the hedge derivative is transferred from accumulated other comprehensive income to earnings. Realized gains and losses on commodity hedge derivatives are recognized in revenues, and realized gains and losses on interest hedge derivatives are recorded as adjustments to interest expense. Settlements of derivatives are included in cash flows from operating activities.

(2) Significant Accounting Policies (Continued)

(m) Comprehensive Income (Loss)

Comprehensive income includes net income (loss) and other comprehensive income, which includes unrealized gains and losses on derivative financial instruments. Pursuant to FASB ASC 815, the Company records deferred hedge gains and losses on its derivative financial instruments that qualify as cash flow hedges as other comprehensive income.

(n) 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.

(o) Concentrations of Credit Risk

Financial instruments, which potentially subject the Company to concentrations of credit risk, consist primarily of trade accounts receivable and derivative financial instruments. Management believes the risk is limited since the Company's customers represent a broad and diverse group of energy marketers and end users. In addition, the Company 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 Company records reserves for uncollectible accounts on a specific identification basis since there is not a large volume of late paying customers. The Company had a reserve for uncollectible receivables as of December 31, 2011, 2010 and 2009 of $0.4 million, $0.2 million and $0.4 million, respectively.

During the year ended December 31, 2011, the Company had only one customer that represented greater than 10.0% individually of its revenue. The customer is located in the LIG segment and represented 12.3% of the consolidated revenue for the year ended December 31, 2011. During the year ended December 31, 2010, three customers accounted for 14.5%, 10.6%, 10.2% of consolidated revenue. During the year ended December 31, 2009, one customer accounted for 12.2% of the consolidated revenue including discontinued operations. As the Company continues to grow and expand, the 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 these customers would not have a material adverse impact on the Company's results of operations because the gross operating margin received from transactions with these customers are not material to the Company's gross operating margin.

(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 a discounted basis 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 the years ended December 31, 2011, 2010 and 2009, such expenditures were not significant.

(2) Significant Accounting Policies (Continued)

(q) Share-Based Awards

The Company recognizes compensation cost related to all stock-based awards, including stock options, in its consolidated financial statements in accordance with FASB ASC 718. 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,		
	2011	2010	2009
Cost of share-based compensation charged to general and administrative expense	$6,405	$8,246	$7,075
Cost of share-based compensation charged to operating expense	1,151	1,323	1,667
Total amount charged to income	$7,556	$9,569	$8,742
Interest of non-controlling partners in share-based compensation	$3,052	$3,900	$3,729
Amount of related income tax benefit recognized in income	$1,670	$2,038	$1,871

(r) Recent Accounting Pronouncements

We have reviewed recently issued accounting pronouncements that became effective during the year ended December 31, 2011, and have determined that none would have a material impact on our Consolidated Financial Statements.

(3) Public Offering of Units by CELP and Certain Provisions of the Partnership Agreement

(a) Issuance of Preferred Units

On January 19, 2010, the Partnership issued approximately $125.0 million of Series A Convertible Preferred Units to an affiliate of Blackstone/GSO Capital Solutions for net proceeds of $120.8 million. The general partner of the Partnership made a contribution of $2.6 million in connection with the issuance to maintain its 2% general partner interest. The 14,705,882 preferred units are convertible by the holders thereof at any time into common units on a one-for-one basis, subject to certain adjustments in the event of certain dilutive issuances of common units. The Partnership has the right to force conversion of the preferred units after three years from the issue date if (i) the daily volume-weighted average trading price of its common units is greater than $12.75 per unit for 20 out of the trailing 30 days ending on two trading days before the date on which the notice is delivered of such conversion, and (ii) the average daily trading volume of common units must have exceeded 250,000 common units for 20 out of the trailing 30 trading days ending on two trading days before the date on which it delivers notice of such conversion. The preferred units are not redeemable. They are entitled to a quarterly distribution that is the greater of $0.2125 per unit or the amount of the quarterly distribution per unit paid to common unitholders, subject to certain adjustments. Such quarterly distribution may be paid in cash, in additional preferred units issued in kind or any combination

(3) Public Offering of Units by CELP and Certain Provisions of the Partnership Agreement (Continued)

thereof, provided that the distribution may not be paid in additional preferred units if the Partnership pays a cash distribution on common units. During 2011 and 2010, the Partnership paid quarterly distributions on its preferred units of $17.2 million and $9.9 million, respectively. A distribution on the preferred units of $4.7 million has been declared for the three months ended December 31, 2011 and was paid in February 2012.

(b) Senior Subordinated Series D Units

On March 23, 2007, the Partnership issued an aggregate of 3,875,340 senior subordinated series D units representing limited partner interests of the Partnership in a private offering. These senior subordinated series D units converted into common units representing limited partner interests of the Partnership on March 23, 2009. The Partnership did not make distributions of available cash from operating surplus, as defined in the partnership agreement, of at least $0.62 per unit on each outstanding common units for the quarter ending December 31, 2008, therefore each senior subordinated series D unit converted into 1.05 common units for a total issuance of 4,069,106 common units.

(c) Cash Distributions

Unless restricted by the terms of the Partnership's credit facility, the Partnership must make distributions of 100.0% of available cash, as defined in the partnership agreement, within 45 days following the end of each quarter commencing with the quarter ending on March 31, 2003. Distributions will generally be made 98.0% to the common and subordinated unitholders and 2.0% to the general partner, subject to the payment of incentive distributions as described below to the extent that certain target levels of cash distributions are achieved.

Under the quarterly incentive distribution provisions, generally its general partner is entitled to 13.0% of amounts the Partnership distributes in excess of $0.25 per unit, 23.0% of the amounts the Partnership distributes in excess of $0.3125 per unit and 48.0% of amounts the Partnership distributes in excess of $0.375 per unit. Incentive distributions totaling $2.4 million and $0.1 million were earned by the Company for the year ended December 31, 2011 and 2010, respectively. No incentive distributions were earned by the general partner for the year ended December 31, 2009. The Partnership paid annual per common unit distributions of $1.17, $0.25, and $0.25 in the years ended December 31, 2011, 2010 and 2009, respectively.

The Partnership increased its fourth quarter distribution on its common units to $0.32 per unit, which was paid February 11, 2012.

(d) Allocation of Partnership Income

Net income is allocated to Crosstex Energy GP, L.P., a wholly-owned subsidiary of the Company, as the Partnership's general partner in an amount equal to its incentive distributions as described in Note 3(c) above. The general partner's share of the Partnership's net income is reduced by stock-based compensation expense attributed to the Company's stock options and restricted stock awarded to officers and employees of the Partnership. The remaining net income after incentive distributions and

(3) Public Offering of Units by CELP and Certain Provisions of the Partnership Agreement (Continued)

Company-related stock-based compensation is allocated pro rata between the 2.0% general partner interest, the subordinated units (excluding senior subordinated units), and the common units. The following table reflects the Company's general partner share of the Partnership's net income (in thousands):

	Years Ended December 31,		
	2011	2010	2009
Income allocation for incentive distributions	$ 2,372	$ 99	$ —
Stock-based compensation attributable to CEI's stock options and restricted shares	(3,119)	(3,906)	(2,966)
2.0% general partner interest in net income (loss)	15	(564)	2,147
General partner share of net income (loss)	$ (732)	$(4,371)	$ (819)

The Company also owned limited partner common units and limited partner subordinated units. The Company's share of the Partnership's net income attributable to its limited partner common units was net income (loss) of $(6.4) million, $(11.6) million and $34.8 million for the years ended December 31, 2011, 2010 and 2009, respectively.

(4) Discontinued Operations, Impairments and Dispositions

(a) Discontinued Operations

The Partnership sold its midstream assets in Alabama, Mississippi and south Texas for $217.6 million in August 2009. Sales proceeds, net of transaction costs and other obligations associated with the sale, of $212.0 million were used to repay long-term indebtedness and the Partnership recognized a gain on sale of $97.2 million. In October 2009, the Partnership sold its Treating assets for net proceeds of $265.4 million. Sales proceeds, net of transaction costs and other obligations associated with the sale, of $258.1 million were used to repay long-term indebtedness and the Partnership recognized a gain on sale of $86.3 million.

The revenues, operating expenses, general and administrative expenses associated directly with the sold assets, depreciation and amortization expense, Treating inventory impairment of $1.0 million during 2009, allocated Texas margin tax and an allocated interest expense related to the operations of the sold assets have been segregated from continuing operations and reported as discontinued operations for all periods. Interest expense of $34.4 million for the year ended 2009 was allocated to discontinued operations related to the debt repaid from the proceeds from the asset dispositions using average historical interest rates for each of the three years. The interest allocation for 2009 also included make-whole interest payments and the write-off of unamortized debt issue costs related to the debt repaid. No corporate office general and administrative expenses have been allocated to income

(4) Discontinued Operations, Impairments and Dispositions (Continued)

from discontinued operations. Following are revenues and income from discontinued operations (in thousands):

	Year ended December 31 2009
Midstream revenues	$327,242
Treating revenues	$ 45,534
Loss from discontinued operations, net of tax	$ (1,519)
Gain from sale of discontinued operations, net of tax	$159,961

(b) Other Disposition

The Partnership disposed of assets that were not considered discontinued operations in the years ended December 31, 2010 and 2009. The 2010 disposition was related to assets in east Texas for a gain of $14.0 million. The 2009 disposition was related to the Arkoma gathering assets in Oklahoma.

(c) Long-Lived Assets and Impairments

Impairments of $1.3 million and $2.9 million were recorded in the years ended December 31, 2010 and 2009, respectively, related to long-lived assets. Impairments during 2009 totaling $2.9 million were taken on the Bear Creek processing plant and the Vermillion treating plant to bring the fair value of the plants to a marketable value for these idle assets. The impairment in 2010 primarily relates to the write down of certain excess pipe inventory prior to its sale.

Potential Changes in Sabine Plant during 2012. Currently, its Sabine plant has a contract with a third-party to fractionate the raw-make NGLs produced by the plant. The Partnership has been unsuccessful in renewing this contract, which expires on March 1, 2012. The Partnership has an interim solution to continue to provide for fractionation of the NGLs produced by the Sabine plant. Ultimately, the Partnership plans to connect the Sabine gas supply to its Eunice plant, which can process the gas and fractionate the produced NGLs. If this processing change is made, the Partnership will likely cease operating the Sabine plant. Although the Partnership does not have specific plans at this time to relocate the Sabine plant once it is idled, the Partnership may consider it for utilization elsewhere in its operations. The net book value of the Sabine plant was $34.0 million as of December 31, 2011. If the plant is idled on a long-term basis as contemplated above, an impairment may be recorded to expense the non-recoverable costs associated with the plant's current location, which are estimated to be less than $15.0 million based on the net book value as of December 31, 2011.

(5) Long-Term Debt

As of December 31, 2011 and 2010, long-term debt consisted of the following (in thousands):

	2011	2010
Bank credit facility (due 2016), interest based on Prime and/or LIBOR plus an applicable margin, interest rate at December 31, 2011 and December 31, 2010 was 2.9% and 4.0%, respectively	$ 85,000	$ —
Senior unsecured notes, net of discount of $11.6 million and $13.5 million, respectively, which bear interest at the rate of 8.875%	713,409	711,512
Series B secured note assumed in the Eunice transaction, which bore interest at the rate of 9.5%	—	7,058
	798,409	718,570
Less current portion	—	(7,058)
Debt classified as long-term	$798,409	$711,512

Maturities. Maturities for the long-term debt as of December 31, 2011 are as follows (in thousands):

2012	$ —
2013	—
2014	—
2015	—
2016	85,000
Thereafter	725,000
Subtotal	810,000
Less discount	(11,591)
Total outstanding debt	$798,409

Credit Facility. The Partnership made three amendments to its bank credit facility in May 2011, July 2011 and January 2012. The amendments contained the following changes:

- Increased borrowing capacity from $420.0 million to $635.0 million;
- Extended maturity from February 2014 to May 2016;
- Increased the maximum permitted leverage ratio to 5.00 to 1.00;
- Decreased the minimum consolidated interest rate coverage ratio during certain fiscal quarters;
- Decreased the interest rates;
- Permitted Apache Midstream LLC ("Apache") to have a first priority lien on certain assets that are the subject of a joint interest arrangement between Apache and Crosstex Permian, LLC ("Permian");

(5) Long-Term Debt (Continued)

- Increased the Partnership's ability to make investments in joint ventures and subsidiaries without such joint ventures and subsidiaries becoming guarantors under the credit agreement; and
- Allowed the Partnership to use multiple banks as letter of credit issuers.

As of December 31, 2011, there was $85.0 million of borrowing and $69.0 million in outstanding letters of credit, under the bank credit facility leaving approximately $331.0 million available for future borrowing based on a borrowing capacity of $485.0 million. Based on the January amendment to increase the credit facility borrowing capacity to $635.0 million and borrowings outstanding as of December 31, 2011, the Partnership's available borrowing would be $481.0 million.

The credit facility is guaranteed by substantially all of the Partnership's subsidiaries and is secured by first priority liens on substantially all of the Partnership's assets and those of the guarantors, including all material pipeline, gas gathering and processing assets, all material working capital assets and a pledge of all of the Partnership's equity interests in substantially all of its 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. The credit facility requires mandatory prepayments of amounts outstanding thereunder with the net proceeds of certain asset sales, extraordinary receipts, equity issuances and debt incurrences, but these mandatory prepayments do not require any reduction of the lenders' commitments under the credit facility.

Under the credit facility, borrowings bear interest at the Partnership's option at the Eurodollar Rate (the British Bankers Association LIBOR Rate) plus an applicable margin or the Base Rate (the highest of the Federal Funds Rate plus 0.50%, the 30-day Eurodollar Rate plus 1.0%, or the administrative agent's prime rate) plus an applicable margin. The Partnership pays a per annum fee on all letters of credit issued under the credit facility and a commitment fee of 0.50% per annum on the unused availability under the credit facility. The letter of credit fee and the applicable margins for the interest rate vary quarterly based on the Partnership's leverage ratio (as defined in the credit facility, being generally computed as the ratio of total funded debt to consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges, or adjusted EBITDA) and are as follows:

Leverage Ratio	Base Rate Loans	Eurodollar Rate Loans	Letter of Credit Fees
Greater than or equal to 4.50 to 1.00	2.00%	3.00%	3.00%
Greater than or equal to 4.00 to 1.00 and less than 4.50 to 1.00	1.75%	2.75%	2.75%
Greater than or equal to 3.50 to 1.00 and less than 4.00 to 1.00	1.50%	2.50%	2.50%
Greater than or equal to 3.00 to 1.00 and less than 3.50 to 1.00	1.25%	2.25%	2.25%
Less than 3.00 to 1.00	1.00%	2.00%	2.00%

Based on the forecasted leverage ratio of 4.00 to 1.00 for 2012, the Partnership expects the margin for the interest rate and letter of credit fee to be in line with the applicable rates above. The credit facility does not have a floor for the Base Rate or the Eurodollar Rate.

(5) Long-Term Debt (Continued)

The amended credit facility includes financial covenants that are tested on a quarterly basis, based on the rolling four-quarter period that ends on the last day of each fiscal quarter. The maximum permitted leverage ratio (as defined in the credit facility, but generally computed as the ratio of total secured funded debt to consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges) is 5.00 to 1.00. The minimum consolidated interest coverage ratio (as defined in the credit facility, but generally computed as the ratio of consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges to consolidated interest charges) is as follows:

- 2.25 to 1.00 for the fiscal quarters ending March 31, 2012 through June 30, 2013;
- 2.50 to 1.00 for September 30, 2013 and each fiscal quarter thereafter.

In addition, the credit facility contains various covenants that, among other restrictions, limit the Partnership's ability to:

- grant or assume liens;
- make investments;
- incur or assume indebtedness;
- engage in mergers or acquisitions;
- sell, transfer, assign or convey assets;
- repurchase its equity, make distributions and certain other restricted payments;
- change the nature of its business;
- engage in transactions with affiliates;
- enter into certain burdensome agreements;
- make certain amendments to the omnibus agreement, or the Partnership's subsidiaries' organizational documents;
- prepay the senior unsecured notes and certain other indebtedness; and
- enter into certain hedging contracts.

The credit facility permits the Partnership to make quarterly distributions to unitholders so long as no default exists under the credit facility.

Each of the following is an event of default under the credit facility:

- failure to pay any principal, interest, fees, expenses or other amounts when due;
- failure to meet the quarterly financial covenants;
- failure to observe any other agreement, obligation, or covenant in the credit facility or any related loan document, subject to cure periods for certain failures;
- the failure of any representation or warranty to be materially true and correct when made;

(5) Long-Term Debt (Continued)

- the Partnership or any of its subsidiaries default under other indebtedness that exceeds a threshold amount;
- judgments against the Partnership or any of its material subsidiaries, in excess of a threshold amount;
- certain ERISA events involving the Partnership or any of its material subsidiaries, in excess of a threshold amount;
- bankruptcy or other insolvency events involving the Partnership or any of its material subsidiaries; and
- a change in control (as defined in the credit facility).

If an event of default relating to bankruptcy or other insolvency events occurs, all indebtedness under the credit facility will immediately become due and payable. If any other event of default exists under the credit facility, the lenders may accelerate the maturity of the obligations outstanding under the credit facility and exercise other rights and remedies. In addition, if any event of default exists under the credit facility, the lenders may commence foreclosure or other actions against the collateral.

If any default occurs under the credit facility, or if the Partnership is unable to make any of the representations and warranties in the credit facility, the Partnership will be unable to borrow funds or have letters of credit issued under the credit facility.

The Partnership expects to be in compliance with the covenants in the credit facility for at least the next twelve months.

Series B Secured Note. On October 20, 2009, the Partnership acquired the Eunice natural gas liquids processing plant and fractionation facility which included an $18.1 million series B secured note. The Partnership paid $11.0 million of principal on the series B secured note in May 2010 and paid the remaining $7.1 million in May 2011.

Senior Unsecured Notes. On February 10, 2010, the Partnership issued $725.0 million in aggregate principal amount of 8.875% senior unsecured notes (the "notes") due on February 15, 2018 pursuant to Rule 144A and Regulation S under the Securities Act at an issue price of 97.907% to yield 9.25% to maturity including the original issue discount (OID). Net proceeds from the sale of the notes of $689.7 million (net of transaction costs and OID), together with borrowings under the credit facility discussed above, were used to repay in full amounts outstanding under the prior bank credit facility and senior secured notes and to pay related fees, costs and expenses, including the settlement of interest rate swaps associated with the prior credit facility. Interest payments on the notes are due semi-annually in arrears in February and August.

The indenture governing the notes contains covenants that, among other things, limit the Partnership's ability and the ability of certain of its subsidiaries to:

- sell assets including equity interests in its subsidiaries;
- pay distributions on, redeem or repurchase units or redeem or repurchase its subordinated debt (as discussed in more detail below);

(5) Long-Term Debt (Continued)

- make investments;
- incur or guarantee additional indebtedness or issue preferred units;
- create or incur certain liens;
- enter into agreements that restrict distributions or other payments from its restricted subsidiaries to the Partnership;
- consolidate, merge or transfer all or substantially all of its assets;
- engage in transactions with affiliates;
- create unrestricted subsidiaries;
- enter into sale and leaseback transactions; or
- engage in certain business activities.

The indenture provides that if the Partnership's fixed charge coverage ratio (the ratio of consolidated cash flow to fixed charges, which generally represents the ratio of adjusted EBITDA to interest charges with further adjustments as defined per the indenture) for the most recently ended four full fiscal quarters is not less than 2.0 to 1.0, the Partnership will be permitted to pay distributions to its unitholders in an amount equal to available cash from operating surplus (each as defined in our partnership agreement) with respect to its preceding fiscal quarter plus a number of items, including the net cash proceeds received by the Partnership as a capital contribution or from the issuance of equity interests since the date of the indenture, to the extent not previously expended. If its fixed charge coverage ratio is less than 2.0 to 1.0, the Partnership will be able to pay distributions to its unitholders in an amount equal to an $80.0 million basket (less amounts previously expended pursuant to such basket), plus the same number of items discussed in the preceding sentence to the extent not previously expended. The Partnership expects to be in compliance with this ratio for at least the next twelve months.

If the notes achieve an investment grade rating from each of Moody's Investors Service, Inc. and Standard & Poor's Ratings Services, many of the covenants discussed above will terminate.

The Partnership may redeem up to 35% of the notes at any time prior to February 15, 2013 with the cash proceeds from equity offerings at a redemption price of 108.875% of the principal amount of the notes (plus accrued and unpaid interest to the redemption date) provided that:

- at least 65% of the aggregate principal amount of the senior notes remains outstanding immediately after the occurrence of such redemption; and
- the redemption occurs within 120 days of the date of the closing of the equity offering.

Prior to February 15, 2014, the Partnership may redeem the notes, in whole or in part, at a "make-whole" redemption price. On or after February 15, 2014, the Partnership may redeem all or a part of the notes at redemption prices (expressed as percentages of principal amount) equal to 104.438% for the twelve-month period beginning on February 15, 2014, 102.219% for the twelve-month period beginning February 15, 2015 and 100.00% for the twelve-month period beginning on

(5) Long-Term Debt (Continued)

February 15, 2016 and at any time thereafter, plus accrued and unpaid interest, if any, to the applicable redemption date on the notes.

Each of the following is an event of default under the indenture:

- failure to pay any principal or interest when due;
- failure to observe any other agreement, obligation, or other covenant in the indenture, subject to the cure periods for certain failures;
- the Partnership or any of its subsidiaries' default under other indebtedness that exceeds a certain threshold amount;
- failures by the Partnership or any of its subsidiaries to pay final judgments that exceed a certain threshold amount; and
- bankruptcy or other insolvency events involving the Partnership or any of its material subsidiaries.

If an event of default relating to bankruptcy or other insolvency events occurs, the senior unsecured notes will immediately become due and payable. If any other event of default exists under the indenture, the trustee under the indenture or the holders of the senior unsecured notes may accelerate the maturity of the senior unsecured notes and exercise other rights and remedies.

(6) Other Long-Term Liabilities

The Partnership entered into 9 and 10-year capital leases for certain compressor equipment. Assets under capital leases are summarized as follows (in thousands):

	Years ended December 31, 2011	Years ended December 31, 2010
Compression equipment	$ 37,199	$37,199
Less: Accumulated amortization	(10,361)	(6,910)
Net assets under capital lease	$ 26,838	$30,289

The following are the minimum lease payments to be made in each of the following years indicated for the capital lease in effect as of December 31, 2011 (in thousands):

Fiscal Year	
2012 through 2016 ($4,582 annually)	$22,910
Thereafter	12,100
Less: Interest	(6,643)
Net minimum lease payments under capital lease	28,367
Less: Current portion of net minimum lease payments	(4,448)
Long-term portion of net minimum lease payments	$23,919

(7) Income Taxes

The Company 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).

	2011	2010	2009
Current tax provision	$ 1,772	$ 1,516	$ 3,394
Deferred tax provision (benefit)	(4,540)	(7,537)	15,229
	$(2,768)	$(6,021)	$18,623

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

	2011	2010	2009
Federal income tax at statutory rate (35%)	$(3,071)	$(6,185)	$11,993
State income taxes, net	(182)	(366)	709
Tax basis adjustment in Partnership related to issuance of common units	—	—	4,475
Non-deductible expenses	153	156	235
Other	332	374	1,211
Tax provision (benefit)	$(2,768)	$(6,021)	$18,623

The following table summarizes the components of the income tax provision (benefit) (in thousands):

	Years Ended December 31,		
	2011	2010	2009
From continuing operations	$(2,768)	$(6,021)	$ (6,020)
From discontinued operations	—	—	24,643
Total tax provision (benefit)	$(2,768)	$(6,021)	$18,623

(7) Income Taxes (Continued)

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

	Years Ended December 31, 2011	2010
Deferred income tax assets:		
Net operating loss carryforward—current	$ —	$ —
Net operating loss carryforward—non-current	45,569	34,365
Investment in the Partnership	20,483	20,483
Other comprehensive income	77	112
Alternative minimum tax carry forward (AMT)	8	8
	66,137	54,968
Less: valuation allowance	(20,483)	(20,483)
	45,654	34,485
Deferred income tax liabilities:		
Property, plant, equipment, and intangible assets—current	(501)	(501)
Property, plant, equipment, and intangible assets—non-current	(129,207)	(122,686)
Other	(1,634)	(1,014)
	(131,342)	(124,201)
Net deferred tax liability	$ (85,688)	$ (89,716)

At December 31, 2011, the Company had a net operating loss carryforward of approximately $120.0 million that expires from 2027 through 2031. The Company also has various state net operating loss carryforwards of approximately $70.4 million which will begin expiring in 2027. Management believes that it is more likely than not that the future results of operations will generate sufficient taxable income to utilize these net operating loss carryforwards before they expire. Although the Company has generated net operating losses in the past, the Company expects to have future taxable income from its investment in the Partnership, generated by the remedial allocations of income among the unitholders and the income generated by operations.

Deferred tax liabilities relating to property, plant, equipment and intangible assets represent, primarily, the Company's share of the book basis in excess of tax basis for assets inside of the Partnership. The Company has also recorded a deferred tax asset in the amount of $20.5 million relating to the difference between its book and tax basis of its investment in the Partnership. Because the Company can only realize this deferred tax asset upon the liquidation of the Partnership and to the extent of capital gains, the Company has provided a full valuation allowance against this deferred tax asset.

Effective as of January 1, 2007, the Company is subject to the Texas margin tax. The new tax law had no significant impact on the Company's 2011 net deferred tax liability.

(7) Income Taxes (Continued)

The Company adopted the provisions of FASB ASC 740-10-25-16 on January 1, 2007. A reconciliation of the beginning and ending amount of the unrecognized tax benefits is as follows (In thousands):

Balance as of December 31, 2009	$1,966
Increases related to prior year tax positions	69
Increases related to current year tax positions	296
Balance as of December 31, 2010	$2,331
Decreases related to prior year tax positions	(6)
Increases related to current year tax positions	325
Balance as of December 31, 2011	$2,650

Unrecognized tax benefits of $2.7 million, if recognized, would affect the effective tax rate. It is unknown when this uncertain tax position will be resolved. In the event additional interest and penalties are incurred prior to resolution, per company policy, such penalties and interest will be recorded to income tax expense.

At December 31, 2011, tax years 2008 through 2011 remain subject to examination by the Internal Revenue Services and tax years 2007 through 2011 remain subject to examination by various state taxing authorities.

(8) Retirement Plans

The Company 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 $2.5 million, $2.3 million, and $3.1 million were made to the plan for the years ended December 31, 2011, 2010 and 2009, respectively.

(9) Employee Incentive Plans

(a) Long-Term Incentive Plans

The Partnership has 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 5,600,000 common unit options and restricted units. The plan is administered by the compensation committee of the Partnership's board of directors. The units issued upon exercise or vesting are newly issued units.

(b) Partnership 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.

(9) Employee Incentive Plans (Continued)

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 in 2011, 2010 and 2009 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, 2011 is provided below:

Crosstex Energy, L.P. Restricted Units:	Number of Units	Weighted Average Grant-Date Fair Value
Non-vested, beginning of period	1,047,374	$10.30
Granted	385,571	15.39
Vested*	(410,418)	14.48
Forfeited	(72,683)	11.72
Non-vested, end of period	949,844	$10.45
Aggregate intrinsic value, end of period (in thousands)	$ 15,406	

* Vested units include 116,458 units withheld for payroll taxes paid on behalf of employees.

A summary of the restricted units' aggregate intrinsic value (market value at vesting date) and fair value of units vested (market value at date of grant) during the years ended December 31, 2011, 2010 and 2009 are provided below (in thousands):

Crosstex Energy, L.P. Restricted Units:	Years Ended December 31, 2011	2010	2009
Aggregate intrinsic value of units vested	$6,438	$11,076	$1,023
Fair value of units vested	$5,945	$ 5,785	$4,158

As of December 31, 2011, there was $5.6 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.

(c) Partnership 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 or its general partner.

(9) Employee Incentive Plans (Continued)

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 to estimate expected forfeiture rates. 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 expected term of the unit option is based on the U.S. Treasury yield curve in effect at the time of the grant. The Partnership used the simplified method to calculate the expected term.

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. The unit options granted in 2009 generally vest based on 3 years of service (one-third after each year of service). There were no options granted in 2011 or 2010. The following weighted average assumptions were used for the Black-Scholes-Merton option-pricing model for grants in 2009:

Crosstex Energy, L.P. Unit Options Granted:	Years ended December 31, 2009
Weighted average distribution yield	—%
Weighted average expected volatility	76.2%
Weighted average risk free interest rate	2.34%
Weighted average expected life	6 years
Weighted average contractual life	10 years
Weighted average of fair value of unit options granted	$ 2.89

(9) Employee Incentive Plans (Continued)

A summary of the unit option activity for the years ended December 31, 2011, 2010 and 2009 is provided below:

	Years Ended December 31,					
	2011		2010		2009	
	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	611,311	$ 6.77	882,836	$6.43	1,304,194	$30.64
Granted(a)	—	—	—	—	636,122	4.46
Issued in Exchange	—	—	—	—	344,319	4.80
Rendered in Exchange	—	—	—	—	(1,032,403)	31.34
Exercised	(128,477)	4.61	(198,725)	4.48	(2,013)	4.08
Forfeited	(31,260)	12.83	(67,183)	9.27	(328,295)	27.51
Expired	—	—	(5,617)	5.37	(39,088)	30.30
Outstanding, end of period	451,574	$ 6.99	611,311	$6.77	882,836	$ 6.43
Options exercisable at end of period	315,742	$ 7.42	278,214	$7.78	159,929	$12.51
Weighted average contractual term (years) end of period:						
Options outstanding	7.2	—	8.2	—	8.7	—
Options exercisable	6.9	—	7.6	—	4.5	—
Aggregate intrinsic value end of period (in thousands):						
Options outstanding	$ 4,648	—	$ 5,350	—	$ 3,143	—
Options exercisable	$ 3,260	—	$ 2,463	—	$ 336	—

(a) No options were granted with an exercise price less than or equal to market value at grant during 2009.

In May 2009, the Partnership's unitholders approved an amendment to the Partnership's long-term incentive plan to allow an option exchange program. This option exchange program was offered to all eligible employees excluding executive officers and directors because options held by employees were "underwater," meaning the exercise price of the options were higher than the current market price of the common units. The terms of the offer included an exchange ratio of 3 old options for 1 replacement option with an exercise price of $4.80 per common unit (120% of the average closing sales price for five trading days prior to the date of grant) which will vest over 2 years (50% after year 1 and 50% after year 2). In June 2009, a total of 453 employees elected to exchange 1,032,403 old options for

(9) Employee Incentive Plans (Continued)

344,319 replacement options pursuant to this option exchange program. There was no incremental compensation cost resulting from the modifications under this option exchange program.

A summary of the unit options intrinsic value exercised (market value in excess of exercise price at date of exercise) and fair value of units vested (value per Black-Scholes-Merton option pricing model at date of grant) during the years ended December 31, 2011, 2010 and 2009 is provided below (in thousands):

	Years Ended December 31,		
Crosstex Energy, L.P. Unit Options:	2011	2010	2009
Intrinsic value of units options exercised	$1,527	$1,470	$ 5
Fair value of unit options vested	$ 563	$ 764	$1,675

As of December 31, 2011, there was $0.3 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 year.

(d) Crosstex Energy, Inc.'s Restricted Stock

The Crosstex Energy, Inc. long-term incentive plan provides for the award of restricted stock (collectively, "Awards") for up to 7,190,000 shares of Crosstex Energy, Inc.'s common stock. As of January 1, 2012, approximately 1,642,396 shares remained available under the long-term incentive plans for future issuance to participants. 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. Awards that are forfeited, terminated or expire unexercised become immediately available for additional awards under the long-term incentive plan.

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 in 2011, 2010 and 2009 generally cliff vest after three years of service. A summary of the restricted stock activity which includes officers and employees of the Partnership and directors of CELP for the year ended December 31, 2011, is provided below:

Crosstex Energy, Inc. Restricted Shares:	Number of Shares	Weighted Average Grant-Date Fair Value
Non-vested, beginning of period	1,108,998	$ 8.64
Granted	617,347	9.44
Vested*	(412,185)	13.64
Forfeited	(92,809)	8.01
Non-vested, end of period	1,221,351	$ 7.40
Aggregate intrinsic value, end of period (in thousands)	$ 15,438	

* Vested units include 113,021 units withheld for payroll taxes paid on behalf of employees.

(9) Employee Incentive Plans (Continued)

A summary of the restricted shares' aggregate intrinsic value (market value at vesting date) and fair value of shares vested (market value at date of grant) during the years ended December 31, 2011, 2010 and 2009 is provided below (in thousands):

	Years Ended December 31,		
Crosstex Energy, Inc. Restricted Shares:	2011	2010	2009
Aggregate intrinsic value of shares vested	$3,915	$3,163	$1,038
Fair value of shares vested	$5,623	$4,388	$4,382

As of December 31, 2011 there was $5.2 million of unrecognized compensation costs related to CEI restricted shares for directors, officers and employees. The cost is expected to be recognized over a weighted average period of 1.9 years.

(e) Crosstex Energy, Inc.'s Stock Options

CEI stock options have not been granted since 2005. A summary of the stock option activity includes officers and employees of the Partnership and directors of CEI for the years ended December 31, 2011, 2010 and 2009 is provided below:

	Years Ended December 31,					
	2011		2010		2009	
	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	37,500	$6.50	67,500	$ 9.54	67,500	$9.54
Forfeited	—	—	(30,000)	13.33	—	—
Outstanding, end of period	37,500	$6.50	37,500	$ 6.50	67,500	$9.54
Options exercisable at end of period	37,500	$6.50	37,500	$ 6.50	67,500	$9.54

A summary of the stock options' intrinsic value (market value in excess of exercise price at date of exercise) exercised and fair value of units vested (value per Black-Scholes-Merton option pricing model at date of grant) during the years ended December 31, 2011, 2010 and 2009 is provided below (in thousands):

	Years Ended December 31,		
Crosstex Energy, Inc. Stock Options:	2011	2010	2009
Fair value of units vested	$—	$—	$49

(10) Derivatives

Interest Rate Swaps

The Partnership did have any interest rate swaps during the year ended December 31, 2011.

The impact of the interest rate swaps on net income is included in other income (expense) in the consolidated statements of operations as part of interest expense, net, as follows (in thousands):

	Years Ended December 31,	
	2010	2009
Change in fair value of derivatives that do not qualify for hedge accounting	$ 22,405	$ 797
Realized losses on derivatives	(26,542)	(19,044)
Loss on interest rate swaps included in continuing operations	$ (4,137)	$(18,247)

Commodity Swaps

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," "storage swaps," "basis swaps," "processing margin swaps" and "put options". 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. Storage swap 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 our systems on one index and selling gas off that same system on a different index. Processing margin financial swaps are used to hedge fractionation spread risk at the Partnership's processing plants relating to the option to process versus bypassing its equity gas. Put options are purchased to hedge against declines in pricing and as such represent options, not obligations, to sell the related underlying volumes at a fixed price.

(10) Derivatives (Continued)

The components of (gain) loss on derivatives in the consolidated statements of operations relating to commodity swaps are (in thousands):

	Years Ended December 31,		
	2011	2010	2009
Change in fair value of derivatives that do not qualify for hedge accounting	$ 726	$1,003	$ 2,816
Realized (gains) losses on derivatives	7,015	7,955	(6,139)
Ineffective portion of derivatives qualifying for hedge accounting	(158)	142	65
Net (gains) losses related to commodity swaps	$7,583	$9,100	$(3,258)
Put option premium mark to market	193	—	—
Net losses included in income from discontinued operations	—	—	264
(Gains) losses on derivatives included in continuing operations	$7,776	$9,100	$(2,994)

The fair value of derivative assets and liabilities relating to commodity swaps are as follows (in thousands):

	Years Ended December 31,	
	2011	2010
Fair value of derivative assets—current, designated	$ 151	$ 1
Fair value of derivative assets—current, non-designated	2,716	5,522
Fair value of derivative assets—long term, non-designated	—	1,169
Fair value of derivative liabilities—current, designated	(702)	(1,066)
Fair value of derivative liabilities—current, non-designated	(4,885)	(6,914)
Fair value of derivative liabilities—long term, non-designated	—	(1,156)
Net fair value of derivatives	$(2,720)	$(2,444)

Set forth below is the summarized notional volumes and fair value of all instruments held for price risk management purposes and related physical offsets at December 31, 2011 (all gas volumes are expressed in MMBtu's and liquids volumes are expressed in gallons). The remaining term of the contracts extend no later than December 2012. Changes in the fair value of the Partnership's mark to market derivatives 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. The ineffective portion is recorded in earnings immediately.

(10) Derivatives (Continued)

Transaction Type	December 31, 2011 Volume	Fair Value
	(In thousands)	
*Cash Flow Hedges:**		
Liquids swaps (short contracts)	(7,876)	$ (551)
Total swaps designated as cash flow hedges		$ (551)
*Mark to Market Derivatives:**		
Swing swaps (short contracts)	(1,600)	$ (1)
Physical offsets to swing swap transactions (long contracts)	1,600	(6)
Basis swaps (long contracts)	5,635	1,341
Physical offsets to basis swap transactions (short contracts)	(1,116)	3,102
Basis swaps (short contracts)	(5,635)	(1,348)
Physical offsets to basis swap transactions (long contracts)	1,085	(3,282)
Processing margin hedges—liquids (short contracts)	(14,338)	(294)
Processing margin hedges—gas (long contracts)	1,620	(2,301)
Processing margin hedges—gas (short contracts)	(187)	163
Storage swap transactions (long contracts)	70	(5)
Storage swap transactions (short contracts)	(360)	462
Total mark to market derivatives		$(2,169)

* All are gas contracts, volume in MMBtu's, except for processing margin hedges—liquids and liquids swaps (volume in gallons).

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. The Partnership primarily deals with two types of counterparties, financial institutions and other energy companies, when entering into financial derivatives on commodities. The Partnership has entered into Master International Swaps and Derivatives Association Agreements that allow for netting of swap contract receivables and payables in the event of default by either party. If the Partnership's counterparties failed to perform under existing swap contracts, the Partnership's maximum loss as of December 31, 2011 of $5.9 million would be reduced to $3.9 million due to the netting feature.

(10) Derivatives (Continued)

Impact of Cash Flow Hedges

The impact of realized gains or losses from derivatives designated as cash flow hedge contracts in the consolidated statements of operations is summarized below (in thousands):

Increase (decrease) in Midstream revenue	Years Ended December 31, 2011	2010	2009
Natural gas	$ —	$ —	$ 2,156
Liquids	(2,772)	(1,733)	9,707
Realized (gain) loss included in income from discontinued operations	—	—	(759)
	$(2,772)	$(1,733)	$11,104

Natural Gas

As of December 31, 2011, the Partnership has no balances in accumulated other comprehensive income related to natural gas.

Liquids

As of December 31, 2011, an unrealized derivative fair value net loss of $0.5 million related to cash flow hedges of liquids price risk was recorded in accumulated other comprehensive income (loss). Of this net amount, a $0.5 million loss is expected to be reclassified into earnings through December 2012. 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.

Derivatives Other Than Cash Flow Hedges

Assets and liabilities related to third party derivative contracts, swing swaps, basis swaps, storage swaps and processing margin swaps 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 net 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, 2011	$(2,169)	$—	$—	$(2,169)

(11) Fair Value Measurements

FASB ASC 820 sets forth a framework for measuring fair value and required disclosures about fair value measurements of assets and liabilities. Fair value under FASB ASC 820 is defined as the price at which an asset could be exchanged in a current transaction between knowledgeable, willing parties. A liability's fair value is defined as the amount that would be paid to transfer the liability to a new obligor, not the amount that would be paid to settle the liability with the creditor. Where available, fair value is based on observable market prices or parameters or derived from such prices or parameters. Where observable prices or inputs are not available, use of unobservable prices or inputs are used to estimate the current fair value, often using an internal valuation model. These valuation techniques involve some level of management estimation and judgment, the degree of which is dependent on the item being valued.

FASB ASC 820 established a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value. These tiers include: Level 1, defined as observable inputs such as quoted prices in active markets; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions.

The Partnership's derivative contracts primarily consist of commodity swap contracts which are not traded on a public exchange. The fair values of commodity swap contracts are determined using discounted cash flow techniques. The techniques incorporate Level 1 and Level 2 inputs for future commodity prices that are readily available in public markets or can be derived from information available in publicly quoted markets. These market inputs are utilized in the discounted cash flow calculation considering the instrument's term, notional amount, discount rate and credit risk and are classified as Level 2 in hierarchy.

Net assets (liabilities) measured at fair value on a recurring basis are summarized below (in thousands):

	Years Ended December 31,	
	2011	2010
	Level 2	Level 2
Interest Rate Swaps	$ —	$ —
Commodity Swaps*	(2,720)	(2,444)
Total	$(2,720)	$(2,444)

* Unrealized gains or losses on commodity derivatives qualifying for hedge accounting are recorded in accumulated other comprehensive income at each measurement date.

Fair Value of Financial Instruments

The estimated fair value of the Company's financial instruments has been determined by the Company 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

(11) Fair Value Measurements (Continued)

indicative of the amount the Company could realize upon the sale or refinancing of such financial instruments (in thousands).

	December 31, 2011		December 31, 2010	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$798,409	$882,500	$718,570	$768,308
Obligations under capital lease	28,367	27,637	31,327	28,807

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

The Partnership had $85.0 million in borrowings under its revolving credit facility included in long-term debt as of December 31, 2011 and no borrowings under this credit facility as of December 31, 2010. Borrowings under the credit facility accrue interest under a floating interest rate structure so the carrying value of such indebtedness approximates fair value for the amounts outstanding under the credit facility. As of December 31, 2011 and December 31, 2010, the Partnership also had borrowings totaling $713.4 million and $711.5 million, net of discount, respectively, under senior unsecured notes with a fixed rate of 8.875% and a series B secured note with a principal amount of $7.1 million as of December 31, 2010 with a fixed rate of 9.5%. The fair value of the senior unsecured notes as of December 31, 2011 and December 31, 2010 was based on third party market quotations. The fair values of the series B secured note as of December 31, 2010 was adjusted to reflect current market interest rates for such borrowings on that date.

(12) Commitments and Contingencies

(a) Leases—Lessee

The Partnership has operating leases for office space, office and field equipment.

The following table summarizes the Partnership's remaining non-cancelable future payments under operating leases with initial or remaining non-cancelable lease terms in excess of one year (in thousands):

2012	$13,191
2013	7,649
2014	5,941
2015	4,535
2016	4,469
Thereafter	5,528
	$41,313

Operating lease rental expense in the years ended December 31, 2011, 2010 and 2009, was approximately $21.9 million, $21.9 million and $30.7 million, respectively.

(12) Commitments and Contingencies (Continued)

(b) Employment and Severance Agreements

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

(c) Environmental Issues

The Partnership acquired 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; however, there can be no assurance that the third parties who have assumed responsibility for remediation of site conditions will fulfill their obligations.

(d) Other

The Company 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.

On June 7, 2010, Formosa Plastics Corporation, Texas, Formosa Plastics Corporation America, Formosa Utility Venture, Ltd., and Nan Ya Plastics Corporation, America filed a lawsuit against Crosstex Energy, Inc., Crosstex Energy, L.P., Crosstex Energy GP, L.P., Crosstex Energy GP, LLC, Crosstex Energy Services, L.P., and Crosstex Gulf Coast Marketing, Ltd. in the 24^{th} Judicial District Court of Calhoun County, Texas, asserting claims for negligence, *res ipsa loquitor*, products liability and strict liability relating to the alleged receipt by the plaintiffs of natural gas liquids into their facilities from facilities operated by the Partnership. The lawsuit alleges that the plaintiffs have incurred at least $35.0 million in damages, including damage to equipment and lost profits. The Partnership has submitted the claim to its insurance carriers and intends to vigorously defend the lawsuit. The Partnership believes that any recovery would be within applicable policy limits. Although it is not possible to predict the ultimate outcome of this matter, the Partnership does not expect that an award in this matter will have a material adverse impact on its consolidated results of operations or financial condition.

At times, the Partnership's gas-utility subsidiaries acquire pipeline easements and other property rights by exercising rights of eminent domain provided under state law. As a result, the Partnership (or its subsidiaries) is a party to a number of lawsuits under which a court will determine the value of pipeline easements or other property interests obtained by the Partnership's gas utility subsidiaries by condemnation. Damage awards in these suits should reflect the value of the property interest acquired and the diminution in the value of the remaining property owned by the landowner. However, some

(12) Commitments and Contingencies (Continued)

landowners have alleged unique damage theories to inflate their damage claims or assert valuation methodologies that could result in damage awards in excess of the amounts anticipated. Although it is not possible to predict the ultimate outcomes of these matters, the Partnership does not expect that awards in these matters will have a material adverse impact on its consolidated results of operations or financial condition.

The Partnership (or its subsidiaries) is defending a number of lawsuits filed by owners of property located near processing facilities or compression facilities constructed by the Partnership as part of its systems. The suits generally allege that the facilities create a private nuisance and have damaged the value of surrounding property. Claims of this nature have arisen as a result of the industrial development of natural gas gathering, processing and treating facilities in urban and occupied rural areas. In January 2012, a plaintiff in one of these lawsuits was awarded a judgment of $2.0 million. The Partnership intends to appeal the matter and will post a bond to secure the judgment pending its resolution. The Partnership has accrued $2.0 million related to this matter as of December 31, 2011 and reflected the related expense in operating expenses in the fourth quarter of 2011. Although it is not possible to predict the ultimate outcomes of these matters, the Partnership does not expect that awards in these matters will have a material adverse impact on its consolidated results of operations or financial condition.

(13) Capital Stock

(a) Common Stock

In October 2006, the Company's stockholders approved an increase in the number of authorized shares of capital stock from 20 million shares, consisting of 19 million shares of common stock and 1 million shares of preferred stock, to 150 million shares, consisting of 140 million shares of common stock and 10 million shares of preferred stock.

(b) Earnings per Share and Anti-Dilutive Computations

Basic earnings per common share was computed by dividing net income by the weighted-average number of common shares outstanding for the periods presented. The computation of diluted earnings per common share further assumes the dilutive effect of common share options and restricted shares.

(13) Capital Stock (Continued)

The following are the share amounts used to compute the basic and diluted earnings per share for the years ended December 31, 2011, 2010 and 2009 (in thousands):

	Years ended December, 31		
	2011	2010	2009
Basic shares:			
Weighted average common shares outstanding	47,150	46,732	46,476
Dilutive shares:			
Weighted average common shares outstanding	47,150	46,732	46,476
Dilutive effect of restricted shares	—	—	59
Dilutive effect of exercise of options	—	—	—
Dilutive shares:	47,150	46,732	46,535

The Company has issued restricted shares that entitle employees to receive non-forfeitable dividends during their vesting period and are therefore considered participating securities for earnings per share calculations. The restricted shares, which participate in earnings and dividends in the same manner as other common shares, were allocated total net income (loss) of $(125,000), $(287,000) and $200,000 for the years ended December 31, 2011, 2010 and 2009, respectively.

(14) Segment Information

Identification of operating segments is based principally upon regions served. The Partnership's reportable segments consist of the natural gas gathering, processing and transmission operations located in north Texas and in the Permian Basin in west Texas (NTX), the pipelines and processing plants located in Louisiana (LIG) and the south Louisiana processing and NGL assets (PNGL). Segment data for the years ended December 31, 2011, 2010 and 2009 do not include assets held for sale. The Partnership's sales are derived from external domestic customers.

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, debt financing costs and its investment in HEP. Profit in the corporate segment for the years ended 2010 and 2009 includes the operating activity of assets sold but not considered discontinued operations as well as intersegment eliminations.

(14) Segment Information (Continued)

Summarized financial information concerning the Partnership's reportable segments as consolidated into the Company's financial statements is shown in the following table.

	LIG	NTX	PNGL	Corporate	Totals
			(In thousands)		
Year Ended December 31, 2011:					
Sales to external customers	$ 811,216	$ 332,026	$ 870,700	$ —	$ 2,013,942
Sales to affiliates	128,130	100,527	40,185	(268,842)	—
Purchased gas and NGLs	(809,471)	(262,708)	(835,440)	268,842	(1,638,777)
Operating expenses	(35,434)	(48,807)	(27,537)	—	(111,778)
Segment profit	$ 94,441	$ 121,038	$ 47,908	$ —	$ 263,387
Gain (loss) on derivatives	$ (6,145)	$ (1,896)	$ 265	$ —	$ (7,776)
Depreciation, amortization and impairments	$ (13,676)	$ (76,535)	$ (31,271)	$ (3,876)	$ (125,358)
Capital expenditures	$ 2,820	$ 73,069	$ 25,618	$ 2,629	$ 104,136
Identifiable assets	$ 305,359	$1,113,431	$ 460,865	$ 82,961	$ 1,962,616
Year Ended December 31, 2010:					
Sales to external customers	$ 880,336	$ 309,771	$ 602,569	$ —	$ 1,792,676
Sales to affiliates	82,688	89,752	—	(172,440)	—
Purchased gas and NGLs	(845,627)	(240,085)	(541,104)	172,440	(1,454,376)
Operating expenses	(33,188)	(46,384)	(25,488)	—	(105,060)
Segment profit	$ 84,209	$ 113,054	$ 35,977	$ —	$ 233,240
Loss on derivatives	$ (3,664)	$ (5,352)	$ (84)	$ —	$ (9,100)
Depreciation, amortization and impairments	$ (12,382)	$ (64,458)	$ (31,661)	$ (4,435)	$ (112,936)
Capital expenditures	$ 9,930	$ 31,678	$ 5,871	$ 1,907	$ 49,386
Identifiable assets	$ 331,261	$1,107,279	$ 493,143	$ 59,420	$ 1,991,103
Year Ended December 31, 2009					
Sales to external customers	$ 830,248	$ 439,265	$ 297,872	$ 16,166	$ 1,583,551
Sales to affiliates	63,581	70,141	—	(133,722)	—
Purchased gas and NGLs	(792,991)	(352,762)	(250,060)	123,484	(1,272,329)
Operating expenses	(27,550)	(49,379)	(30,991)	(2,474)	(110,394)
Segment profit	$ 73,288	$ 107,265	$ 16,821	$ 3,454	$ 200,828
Gain (loss) on derivatives	$ (467)	$ 2,289	$ 1,172	$ —	$ 2,994
Depreciation, amortization and impairments	$ (13,070)	$ (65,956)	$ (35,284)	$ (7,746)	$ (122,056)
Capital expenditures	$ 30,992	$ 43,289	$ 7,973	$ 1,153	$ 83,407
Identifiable assets	$ 342,631	$1,168,182	$ 505,155	$ 64,265	$ 2,080,233

(14) Segment Information (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,		
	2011	2010	2009
Segment profits	$ 263,387	$ 233,240	$ 200,828
General and administrative expenses	(55,516)	(51,172)	(62,491)
Gain (loss) on derivatives	(7,776)	(9,100)	2,994
Gain (loss) on sale of property	(264)	13,881	666
Depreciation, amortization and impairments	(125,358)	(112,936)	(122,056)
Operating income	$ 74,473	$ 73,913	$ 19,941

(15) Quarterly Financial Data (Unaudited)

Summarized unaudited quarterly financial data is presented below.

	First	Second	Third	Fourth	Total
	(In thousands, except per unit data)				
2011:					
Revenues	$489,770	$525,735	$517,498	$480,939	$2,013,942
Operating income	$ 19,238	$ 22,243	$ 15,612	$ 17,380	$ 74,473
Net income (loss) attributable to the non-controlling partners	$ 1,770	$ 2,648	$ (364)	$ 674	$ 4,728
Net loss attributable to the Crosstex Energy, Inc	$ (1,536)	$ (1,073)	$ (1,588)	$ (1,810)	$ (6,007)
Basic earnings per common share	$ (0.03)	$ (0.02)	$ (0.04)	$ (0.03)	$ (0.12)
Diluted earnings per common share	$ (0.03)	$ (0.02)	$ (0.04)	$ (0.03)	$ (0.12)
2010:					
Revenues	$468,658	$442,048	$454,735	$427,235	$1,792,676
Operating income	$ 23,788	$ 16,820	$ 16,026	$ 17,279	$ 73,913
Net income (loss) attributable to the non-controlling partners	$ (9,611)	$ 233	$ (683)	$ 199	$ (9,862)
Net income (loss) attributable to the Crosstex Energy, Inc	$ (5,402)	$ (2,181)	$ (1,980)	$ (2,088)	$ (11,651)
Basic earnings per common share	$ (0.11)	$ (0.05)	$ (0.04)	$ (0.04)	$ (0.24)
Diluted earnings per common share	$ (0.11)	$ (0.05)	$ (0.04)	$ (0.04)	$ (0.24)

(1) The Partnership determined that revenues and purchased gas costs related to a new gas purchase arrangement were improperly classified as energy trading activities resulting in the netting of revenue and purchased gas which should have been shown on a gross basis in its previously-issued financial statements for the three months ended March 31, 2011 and June 30, 2011. As a result both revenues and purchased gas were understated by $39.5 million and $29.6 million for the three months ended March 31, 2011 and June 30, 2011. The revenue numbers for both March 31, 2011 and June 30, 2011 properly reflect this adjustment. There is no impact on operating income.

Schedule I

CROSSTEX ENERGY, INC. (PARENT COMPANY)

CONDENSED BALANCE SHEETS

	December 31, 2011	December 31, 2010
	(In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 6,200	$ 5,083
Prepaid expenses and other	14	40
Total current assets	6,214	5,123
Investment in the Partnership	234,702	260,933
Total assets	$240,916	$266,056
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Payable to the Partnership	$ —	$ 22
Other current liabilities	501	241
Total current liabilities	501	263
Deferred tax liability	77,995	81,378
Stockholders' equity:		
Common stock	471	468
Additional paid-in capital	244,211	242,390
Accumulated deficit	(82,177)	(58,298)
Accumulated other comprehensive loss	(85)	(145)
Total stockholders' equity	162,420	184,415
Total liabilities and stockholders' equity	$240,916	$266,056

See "Notes to Consolidated Financial Statements" of Crosstex Energy, Inc. included in this report.

CROSSTEX ENERGY, INC. (PARENT COMPANY)

CONDENSED STATEMENTS OF OPERATIONS

	Years ended December 31,		
	2011	2010	2009
	(In thousands, except per unit data)		
Operating income and expenses:			
Income (loss) from investment in the Partnership	$ (7,192)	$(16,042)	$ 33,875
General and administrative expenses	(2,715)	(2,758)	(2,584)
Operating income (loss)	(9,907)	(18,800)	31,291
Other income (expense):			
Interest and other income	6	7	48
Income (loss) before income taxes	(9,901)	(18,793)	31,339
Income tax benefit (provision)	3,894	7,142	(15,697)
Net income (loss)	$ (6,007)	$(11,651)	$ 15,642
Net income (loss) per common share:			
Basic	$ (0.12)	$ (0.24)	$ 0.33
Diluted	$ (0.12)	$ (0.24)	$ 0.33
Weighted average common shares outstanding			
Basic	$47,150	$ 46,732	$ 46,476
Diluted	$47,150	$ 46,732	$ 46,535

See "Notes to Consolidated Financial Statements" of Crosstex Energy, Inc. included in this report.

CROSSTEX ENERGY, INC. (PARENT COMPANY)

CONDENSED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2011	2010	2009
	(In thousands)		
Cash flows from operating activities:			
Net income (loss)	$ (6,007)	$(11,651)	$ 15,642
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Loss (income) from investment in the Partnership, including discontinued operations	7,196	16,041	(33,929)
Deferred tax provision (benefit)	(3,896)	(7,142)	15,697
Stock-based compensation	249	292	113
Changes in assets and liabilities, net of acquisition effects:			
Accounts receivable, prepaid expenses and other	(57)	(6)	463
Accounts payable, and other accrued liabilities	238	71	(116)
Net cash used in operating activities	(2,277)	(2,395)	(2,130)
Cash flows from investing activities:			
Investment in the Partnership	(163)	(2,807)	(21)
Distributions from the Partnership	22,497	4,435	4,333
Net cash provided by investing activities	22,334	1,628	4,312
Cash flows from financing activities:			
Conversion of restricted units, net of units withheld for taxes	(1,068)	(705)	(354)
Common dividends paid	(17,872)	(3,368)	(4,228)
Net cash provided by (used in) financing activities	(18,940)	(4,073)	(4,582)
Net increase (decrease) in cash and cash equivalents	1,117	(4,840)	(2,400)
Cash, beginning of period	5,083	9,923	12,323
Cash, end of period	$ 6,200	$ 5,083	$ 9,923

See "Notes to Consolidated Financial Statements" of Crosstex Energy, Inc. included in this report.

Schedule II

CROSSTEX ENERGY, INC.

VALUATION AND QUALIFYING ACCOUNTS

	Balance at Beginning of Period	Charged to Costs and Expenses	Deductions	Balance at End of Period
		(In thousands)		
Year ended December 31, 2011 Allowance for doubtful accounts	$ 163	$1,346	$1,104	$405
Year ended December 31, 2010 Allowance for doubtful accounts	$ 410	$ 395	$ 642	$163
Year ended December 31, 2009 Allowance for doubtful accounts	$3,655	$1,070	$4,315	$410