UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

Form 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d) of the
Securities Exchange Act of 1934

Date of Report (date of earliest event reported): April 11, 2007

CROSSTEX ENERGY, L.P.

(Exact name of registrant as specified in its charter)

DELAWARE	000-50067	16-1616605
(State or Other Jurisdiction of Incorporation or Organization)	(Commission File Number)	(I.R.S. Employer Identification No.)

2501 CEDAR SPRINGS RD DALLAS, TX	75201
(Address of Principal Executive Offices)	(Zip Code)

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

(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240-13e-4(c))

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Item 8.01 Other Events.

The audited consolidated balance sheet of Crosstex Energy GP, L.P. as of December 31, 2006 and the related notes thereto are filed as an Exhibit to this Current Report on Form 8-K. Crosstex Energy GP, L.P. is the general partner of Crosstex Energy, L.P.

Item 9.01. Financial Statements and Exhibits

(d) Exhibits.

EXHIBIT NUMBER		DESCRIPTION
23.1	—	Consent of KPMG LLP
99.1	—	Audited Consolidated Balance Sheet of Crosstex Energy GP, L.P.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

CROSSTEX ENERGY, L.P.

By: Crosstex Energy GP, L.P., its General Partner

By: Crosstex Energy GP, LLC, its General Partner

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

Date: April 11, 2007

INDEX TO EXHIBITS

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23.1	—	Consent of KPMG LLP
99.1	—	Audited Consolidated Balance Sheet of Crosstex Energy GP, L.P.

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

The Partners of
Crosstex Energy, L.P.:

We consent to the incorporation by reference in the registration statements on Forms S-8 (Nos. 333-107025 and 333-127645) and Forms S-3 (Nos. 333-116538, 333-128282, 333-134712 and 333-135951) of Crosstex Energy, L.P. of our report dated April 11, 2007, with respect to the consolidated balance sheet of Crosstex Energy GP, L.P. as of December 31, 2006, which report appears herein this Form 8-K of Crosstex Energy, L.P.

As discussed in Note 2 to the consolidated balance sheet, effective January 1, 2006, Crosstex Energy GP, L.P. and subsidiaries adopted the provisions of Statement of Financial Accounting Standards No. 123 (revised 2004), *Share Based Payment* and Emerging Issues Task Force Issue No. 04-5, *Investor's Accounting for an Investment in a Limited Partnership When the Investor is the Sole General Partner and the Limited Partners Have Certain Rights.*

/s/ KPMG LLP

Dallas, TX
April 11, 2007

Report of Independent Registered Public Accounting Firm

The Partners
Crosstex Energy GP, L.P.:

We have audited the accompanying consolidated balance sheet of Crosstex Energy GP, L.P. (a Delaware limited partnership) and subsidiaries as of December 31, 2006. This consolidated financial statement is the responsibility of the Partnership's management. Our responsibility is to express an opinion on this consolidated financial statement 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 the balance sheet is free of material misstatement. An audit of a balance sheet includes examining, on a test basis, evidence supporting the amounts and disclosures in that balance sheet, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall balance sheet presentation. We believe that our audit of the balance sheet provides a reasonable basis for our opinion.

In our opinion, the consolidated balance sheet referred to above presents fairly, in all material respects, the financial position of Crosstex Energy GP, L.P. and subsidiaries as of December 31, 2006, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 2 to the consolidated balance sheet, effective January 1, 2006, Crosstex Energy GP, L.P. and subsidiaries adopted the provisions of Statement of Financial Accounting Standards No. 123 (revised 2004), *Share Based Payment* and Emerging Issues Task Force Issue No. 04-5, *Investor's Accounting for an Investment in a Limited Partnership When the Investor is the Sole General Partner and the Limited Partners Have Certain Rights.*

/s/ KPMG LLP

Dallas, Texas
April 11, 2007

CROSSTEX ENERGY GP, L.P.
Consolidated Balance Sheet
December 31, 2006
(In thousands)

ASSETS	
Current assets:	
Cash and cash equivalents	$ 825
Accounts receivable:	
Trade, net of allowance for bad debts of $618	35,787
Accrued revenues	331,236
Imbalances	5,159
Affiliated companies	23
Note receivable	926
Other	2,864
Fair value of derivative assets	23,048
Natural gas and natural gas liquids, prepaid expenses, and other	10,468
Total current assets	410,336
Property and equipment:	
Transmission assets	335,599
Gathering systems	285,706
Gas plants	460,774
Other property and equipment	30,816
Construction in process	129,373
Total property and equipment	1,242,268
Accumulated depreciation	(136,455)
Total property and equipment, net	1,105,813
Fair value of derivative assets	3,812
Intangible assets, net of accumulated amortization of $31,673	638,602
Goodwill	24,495
Other assets, net	11,417
Total assets	$ 2,194,475
LIABILITIES AND PARTNERS' EQUITY	
Current liabilities:	
Drafts payable	$ 47,948
Accounts payable	31,764
Accrued gas purchases	325,151
Accrued imbalances payable	2,855
Accrued construction in process costs	29,942
Fair value of derivative liabilities	12,141
Current portion of long-term debt	10,012
Other current liabilities	30,458
Total current liabilities	490,271
Long-term debt	977,118
Deferred tax liability	8,996
Minority interest	695,059
Fair value of derivative liabilities	2,558
Commitments and contingencies	—
Partners' equity	20,473
Total liabilities and partners' equity	$ 2,194,475

See accompanying notes to consolidated balance sheet.

(1) Organization and Summary of Significant Agreements

(a) Description of Business

Crosstex Energy GP, L.P. (the General Partner) is a Delaware limited partnership formed on July 12, 2002 to become the General Partner of Crosstex Energy, L.P. The General Partner is an indirect wholly-owned subsidiary of Crosstex Energy, Inc. (CEI). The General Partner owns a 2% general partner interest in Crosstex Energy, L.P. (CELP). CELP is engaged in the gathering, transmission, treating, processing and marketing of natural gas. CELP connects the wells of natural gas producers in the geographic areas of its gathering systems in order to purchase the gas production, treats natural gas to remove impurities to ensure that it meets pipeline quality specifications, processes natural gas for the removal of natural gas liquids or NGLs, transports natural gas and ultimately provides an aggregated supply of natural gas to a variety of markets. In addition, CELP purchases natural gas from producers not connected to its gathering systems for resale and sells natural gas on behalf of producers for a fee.

(b) Partnership Ownership

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

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

(c) Basis of Presentation

The accompanying consolidated balance sheet includes the assets and liabilities of operations of the General Partner and CELP. The General Partner has no independent operations and no material assets outside of its interest in CELP. The General Partner proportionately consolidates CELP's undivided 12.4% interest in a carbon dioxide processing plant acquired by CELP in June 2004 and CELP's undivided 59.27% interest in a gas plant acquired by CELP in November 2005 (23.85%) and May 2006 (35.42%). The General Partner also consolidates CELP's joint venture interest in Crosstex DC Gathering, J.V. (CDC) as discussed more fully in Note 4, in accordance with FASB Interpretation No. 46R, *Consolidation of Variable Interest Entities* (FIN No. 46R). The consolidated operations are hereafter referred to herein collectively as the "Partnership." All material intercompany balances and transactions have been eliminated.

(2) Significant Accounting Policies

(a) Adoption of Emerging Issues Task Force Issue No. 04-5, "Investor's Accounting for an Investment in a Limited Partnership When the Investor is the Sole General Partner and the Limited Partners Have Certain Rights".

Effective January 1, 2006, the General Partner adopted Emerging Issues Task Force Issue 04-5, "*Investor's Accounting for an Investment in a Limited Partnership When the Investor is the Sole General Partner and the Limited Partners Have Certain Rights"* (EITF 04-5). The General Partner is required to consolidate CELP in accordance with EITF 04-5 because it has substantive participating rights as the general partner of CELP.

(b) Management's Use of Estimates

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

(c) Cash and Cash Equivalents

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

(d) Natural Gas and Natural Gas Liquids Inventory

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

(e) Property, Plant, and Equipment

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

Other property and equipment is primarily comprised of computer software and equipment, furniture, fixtures, leasehold improvements and office equipment. Property, plant and equipment are recorded at cost. Repairs and maintenance are charged against income when incurred. Renewals and betterments, which extend the useful life of the properties, are capitalized. Interest costs are capitalized to property, plant and equipment during the period the assets are undergoing preparation for intended use.

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

	Useful Lives
Transmission assets	15-25 years
Gathering systems	7-15 years
Gas treating, gas processing and carbon dioxide plants	15 years
Other property and equipment	3-7 years

Statement of Financial Accounting Standards (SFAS) No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, requires long-lived assets to be reviewed whenever events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. In order to determine whether an impairment has occurred, the Partnership compares the net book value of the asset to the undiscounted expected future net cash flows. If impairment has occurred, the amount of such impairment is determined based on the expected future net cash flows discounted using a rate commensurate with the risk associated with the asset.

When determining whether impairment of one of our long-lived assets has occurred, the Partnership must estimate the undiscounted cash flows attributable to the asset. The Partnership's estimate of cash flows is based on assumptions regarding the purchase and resale margins on natural gas, volume of gas available to the asset, markets available to the asset, operating expenses, and future natural gas prices and NGL product prices. The amount of availability of gas to an asset is sometimes based on assumptions regarding future drilling activity, which may be dependent in part on natural gas prices. Projections of gas volumes and future commodity prices are inherently subjective and contingent upon a number of variable factors. Any significant variance in any of the above assumptions or factors could materially affect our cash flows, which could require us to record an impairment of an asset.

(f) Goodwill and Intangibles

The Partnership has approximately $24.5 million of goodwill at December 31, 2006. During the formation of the Partnership in May 2001, $5.4 million of goodwill was created and later amortized by $0.5 million. Goodwill of approximately $1.7 million in 2005 and $17.9 million in 2006 resulted from three acquisitions in our Treating segment. The goodwill related to the formation of the Partnership has been allocated to the Midstream segment. Goodwill is assessed at least annually for impairment.

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

(g) Other Assets

Unamortized debt issuance costs totaling $11.4 million at December 31, 2006 are included in other noncurrent assets. Debt issuance costs are amortized into interest expense using the effective-interest method over the term of the debt for the senior secured notes. Debt issuance costs are amortized using the straight-line method over the term of the debt for the bank credit facility because borrowings under the bank credit facility cannot be forecasted for an effective-interest computation.

(h) Gas Imbalance Accounting

Quantities of natural gas over-delivered or under-delivered related to imbalance agreements are recorded monthly as receivables or payables using weighted average prices at the time of the imbalance. These imbalances are typically settled with deliveries of natural gas. The Partnership had imbalance payables of $2.9 million at December 31, 2006 which approximates the fair value of these imbalances. The Partnership had imbalance receivables of $5.2 million at December 31, 2006 which are carried at the lower of cost or market value.

(i) Asset Retirement Obligations

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

(j) Commodity Risk Management

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

The Partnership recognizes all derivative and hedging instruments in the statements of financial position as either assets or liabilities and measures them at fair value in accordance with Statement of Financial Accounting Standards No. 133 (SFAS No. 133), *Accounting for Derivative Instruments and Hedging Activities*. If a derivative does not qualify for hedge accounting, it must be adjusted to fair value through earnings. However, if a derivative does qualify for hedge accounting, depending on the nature of the hedge, changes in fair value can be offset against the change in fair value of the hedged item through earnings or recognized in other comprehensive income until such time as the hedged item is recognized in earnings. To qualify for cash flow hedge accounting, the cash flows from the hedging instrument must be highly effective in offsetting changes in cash flows due to changes in the underlying item being hedged. In addition, all hedging relationships must be designated, documented and reassessed periodically.

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

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

(k) Energy Trading Activities

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

The Partnership manages its price risk related to future physical purchase or sale commitments for its energy trading activities by entering into either corresponding physical delivery contracts or financial instruments with an objective to balance the Partnership’s future commitments and significantly reduce its risk to the movement in natural gas prices. However, the Partnership is subject to counter-party risk for both the physical and financial contracts. The Partnership’s energy trading contracts qualify as derivatives, and accordingly, the Partnership continues to use mark-to-market accounting for both physical and financial contracts of its energy trading activities.

(l) Comprehensive Income (Loss)

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

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

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

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

(n) Income Taxes

The Partnership is generally not subject to income taxes, except as discussed below, because its income is taxed directly to its partners including CEI as the indirect owner of the General Partner. The net tax basis in the Partnership’s assets and liabilities is less than the reported amounts on the financial statements by approximately $205.3 million as of December 31, 2006. Effective January 1, 2007, the Partnership will be subject to the gross margin tax enacted by the state of Texas on May 1, 2006. The new tax law had no significant impact on the Partnership’s deferred tax liability.

The Partnership owns four entities that are treated as taxable corporations for income tax purposes. The entity structure was formed when the Partnership acquired the stock of these entities in 2004 to effect the matching of the tax cost to the Partnership of a step-up in the basis of the assets to fair market value with the recognition of benefits of the step-up by the Partnership. The deferred tax liability represents future taxes payable on the difference between the fair value and tax basis of the assets acquired. The Partnership, through these entities, generated a net operating loss of $4.8 million during 2005 as a result of a tax loss on a property sale of which $0.9 million was carried back to 2004, $1.9 million was utilized in 2006 and substantially all of the remaining $2.0 million will be utilized in 2007.

The Partnership provides for income taxes using the liability method. The principal component of the Partnership’s net deferred tax liability is as follows as of December 31, 2006 (in thousands):

Deferred income tax assets:	
Net operating loss carryforward — current	$ 718
Net operating loss carryforward — long-term	49
Alternative minimum tax credit carryover — long-term	59
	$ 826

Deferred income tax liabilities:	
Property, plant, equipment, and intangible assets-current	$ (501)
Property, plant, equipment and intangible assets-long-term	(9,103)
	$ (9,604)
Net deferred tax liability	$ (8,778)

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

(o) Environmental Costs

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

(p) Cash Distributions

In accordance with the partnership agreement, CELP must make distributions of 100% of available cash, as defined in the partnership agreement, within 45 days following the end of each quarter. Distributions will generally be made 98% to the common and subordinated unitholders and 2% to the General Partner, subject to the payment of incentive distributions as described below to the extent that certain target levels of cash distributions are achieved. CELP's senior secured credit facility prohibits CELP from declaring distributions to unitholders if any event of default exists or would result from the declaration of distributions. See Note (5) for a description of the bank credit facility covenants.

Under the quarterly incentive distribution provisions, generally the General Partner is entitled to 13% of amounts CELP distributes in excess of $0.25 per unit, 23% of the amounts CELP distributes in excess of $0.3125 per unit and 48% of amounts CELP distributes in excess of $0.375 per unit. Incentive distributions totaling $20.4 million were earned by the General Partner for the year ended December 31, 2006. To the extent there is sufficient available cash, the holders of common units are entitled to receive the minimum quarterly distribution of $0.25 per unit, plus arrearages, prior to any distribution of available cash to the holders of subordinated units. Subordinated units will not accrue any arrearages with respect to distributions for any quarter. CELP paid annual per common unit distributions of $2.18 for the year ended December 31, 2006.

CELP increased its fourth quarter 2006 distribution on its common and subordinated units to $0.56 per unit, which distribution was paid on February 15, 2007.

(q) Minority Interest

Minority interest represents third party ownership interests in the net assets of our subsidiaries that primarily include the limited partners of CELP and CELP's joint venture partner. For financial reporting purposes, the assets and liabilities of our majority owned subsidiaries are consolidated with those of our own, with any third party ownership interest in such amounts presented as minority interest.

(r) Option Plans

Effective January 1, 2006, the Partnership adopted the provisions of SFAS No. 123R, "*Share-Based Payment"* (FAS No. 123R) which requires compensation related to all stock-based awards, including stock options, be recognized in the consolidated financial statements. The Partnership applied the provisions of Accounting Principles Board Opinion No. 25, "*Accounting for Stock Issued to Employees"* (APB No. 25), for periods prior to January 1, 2006.

The Partnership elected to use the modified-prospective transition method for adopting SFAS No. 123R. Under the modified-prospective method, awards that are granted, modified, repurchased, or canceled after the date of adoption are measured and accounted for under SFAS No. 123R. The unvested portion of awards that were granted prior to the effective date are also accounted for in accordance with SFAS No.123R. The Partnership adjusted compensation cost for actual forfeitures as they occurred under APB No. 25 for periods prior to January 1, 2006. Under SFAS No.123R, the Partnership is required to estimate forfeitures in determining periodic compensation cost.

The Partnership and CEI each have similar unit or share-based payment plans for employees. 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.

(s) Recent Accounting Pronouncements

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

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

(3) Significant Asset Acquisitions

On June 29, 2006, the Partnership acquired certain natural gas gathering pipeline systems and related facilities in the Barnett Shale (the North Texas Gathering (NTG) assets) from Chief Holdings LLC (Chief) for a purchase price of approximately $475.3 million (the Chief Acquisition). The NTG assets include five gathering systems, located in parts of Parker, Tarrant, Denton, Palo Pinto, Erath, Hood, Somervell, Hill and Johnson counties in Texas. The NTG assets also included a 125 million cubic feet per day carbon dioxide treating plant and compression facilities with 26,000 horsepower. The gas gathering systems consisted of approximately 250 miles of existing gathering pipelines, ranging from four inches to twelve inches in diameter. The Partnership plans to build up to an additional 400 miles of pipelines as production in the area is drilled and developed. The gathering systems had the capacity to deliver approximately 250,000 MMBtu per day at the date of acquisition.

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

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

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

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

The Partnership financed the Chief Acquisition with borrowings of approximately $105.0 million under its bank credit facility, net proceeds of approximately $368.3 million from the private placement of senior subordinated series C units, including approximately $9.0 million of equity contributions from the General Partner and $6.0 million of cash.

(4) Investment in Joint Venture and Note Receivable

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

In connection with the formation of CDC, the Partnership agreed to loan the CDC partner up to $1.5 million for its initial capital contribution. The loan bears interest at an annual rate of prime plus 2%. CDC makes payments directly to the Partnership attributable to CDC partner's 50% share of distributable cash flow to repay the loan. Any balance remaining on the note is due in August 2007. The balance remaining on the note of $0.9 million is included in current notes receivable as of December 31, 2006.

(5) Long-Term Debt

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

Bank credit facility, interest based on Prime or LIBOR plus an applicable margin, interest rate at December 31, 2006 was 7.20%	$ 488,000
Senior secured notes, weighted average interest rate at December 31, 2006 of 6.76%	498,530
Note payable to Florida Gas Transmission Company	600
	987,130
Less current portion	(10,012)
Debt classified as long-term	$ 977,118

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

At December 31, 2006, $564.3 million was outstanding under the facility, including $76.3 million of letters of credit, leaving approximately $435.7 million available for future borrowings. The facility will mature in June 2011, at which time it will terminate and all outstanding amounts shall be due and payable. Amounts borrowed and repaid under the credit facility may be re-borrowed.

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

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

The credit agreement prohibits the Partnership from declaring distributions to unit-holders if any event of default, as defined in the credit agreement, exists or would result from the declaration of distributions. In addition, the bank credit facility contains various covenants that, among other restrictions, limit the Partnership's ability to:

- incur indebtedness;
- grant or assume liens;
- make certain investments;
- sell, transfer, assign or convey assets, or engage in certain mergers or acquisitions;
- make distributions;
- change the nature of its business;
- enter into certain commodity contracts;
- make certain amendments to the Partnership's or its operating partnership's partnership agreement; and
- engage in transactions with affiliates.

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

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

Each of the following will be an event of default under the bank credit facility:

- failure to pay any principal, interest, fees, expenses or other amounts when due;
- failure to observe any agreement, obligation, or covenant in the credit agreement, subject to cure periods for certain failures;
- certain judgments against the Partnership or any of its subsidiaries, in excess of certain allowances;
- certain ERISA events involving the Partnership or the Partnership's subsidiaries;
- a change in control (as defined in the credit agreement); and
- the failure of any representation or warranty to be materially true and correct when made.

In November 2006, the Partnership entered into an interest rate swap covering a principal amount of $50.0 million under the credit facility for a period of three years. The Partnership is subject to interest rate risk on our credit facility. The interest rate swap reduces this risk by fixing the LIBOR rate, prior to credit margin, at 4.95%, on $50.0 million of related debt outstanding over the term of the swap agreement which expires on November 30, 2009. The fair value of the interest rate swap at December 31, 2006 was a $0.1 million asset.

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

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

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

2006.

These notes represent senior secured obligations of the Partnership and will rank at least *pari passu* in right of payment with the bank credit facility. The notes are secured, on an equal and ratable basis with obligations of the Partnership under the credit facility, by first priority liens on all of its material pipeline, gas gathering and processing assets, all material working capital assets and a pledge of all its equity interests in certain of its subsidiaries. The senior secured notes are guaranteed by the Partnership's subsidiaries.

The $40.0 million of senior secured notes issued in 2003 are redeemable, at the Partnership's option and subject to certain notice requirements, at a purchase price equal to 100% of the principal amount together with accrued interest, plus a make-whole amount determined in accordance with the master shelf agreement. The senior secured notes issued 2004, 2005 and 2006 provide for a call premium of 103.5% of par beginning three years after issuance at rates declining from 103.5% to 100.0%. The notes are not callable prior to three years after issuance. During 2007 the notes may also incur an additional fee each quarter ranging from 0.08% to 0.15% per annum on the outstanding borrowings if the Partnership's leverage ratio, as defined in the agreement, exceeds certain levels during such quarterly period.

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

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

The Partnership was in compliance with all debt covenants at December 31, 2006 and expects to be in compliance with debt covenants for the next twelve months.

Intercreditor and Collateral Agency Agreement. In connection with the execution of the master shelf agreement, the lenders under the bank credit facility and the purchasers of the senior secured notes have entered into an Intercreditor and Collateral Agency Agreement, which has been acknowledged and agreed to by the Partnership and its subsidiaries. This agreement appointed Bank of America, N.A. to act as collateral agent and authorized Bank of America to execute various security documents on behalf of the lenders under the bank credit facility and the purchasers of the senior secured notes. This agreement specifies various rights and obligations of lenders under the bank credit facility, holders of senior secured notes and the other parties thereto in respect of the collateral securing the Partnership's obligations under the bank credit facility and the master shelf agreement.

Other Note Payable. In June 2002, as part of the purchase price of Florida Gas Transmission Company (FGTC), the Partnership issued a note payable for $0.8 million to FGTC that is payable in $0.1 million annual increments through June 2006 with a final payment of $0.6 million due in June 2007. The note bears interest payable annually at LIBOR plus 1%.

Maturities. Maturities for the long-term debt as of December 31, 2006 are as follows (in thousands):

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

(6) Employee Incentive Plans

(a) Long-Term Incentive Plan

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

(b) Restricted Units

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

The restricted units are intended to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of the common units. Therefore, plan participants will not pay any consideration for the common units they receive and the Partnership will receive no remuneration for the units. The restricted units include a tandem award that entitles the participant to receive cash payments equal to the cash distributions made by the Partnership with respect to its outstanding common units until the restriction period is terminated or the restricted units are forfeited. The restricted units granted prior to 2005 generally vest based on five years of service (25% in years 3 and 4 and 50% in year 5) and the restricted units granted in 2005 and 2006 generally cliff vest after three years of service.

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

Crosstex Energy, L.P. Restricted Units:

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

The aggregate intrinsic value of vested units during the year ended December 31, 2006 was $0.7 million. As of December 31, 2006, there was $5.8 million of unrecognized compensation cost related to non-vested restricted units. That cost is expected to be recognized over a weighted-average period of 1.8 years.

(c) Unit Options

Unit options will have an exercise price that is not less than the fair market value of the units on the date of grant. In general, unit options granted will become exercisable over a period determined by the compensation committee. In addition, unit options will become exercisable upon a change in control of the Partnership, its general partner or its general partner's general partner.

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

Unit options are generally awarded with an exercise price equal to the market price of the Partnership's common units at the date of grant. The unit options granted prior to 2005 generally vest based on five years of service (25% in years 3 and 4 and 50% in year 5) and the unit options granted in 2005 and 2006 generally vest based on 3 years of service (one-third after each year of service). The following weighted average assumptions were used for the Black-Scholes option-pricing model for grants in 2006:

Crosstex Energy, L.P. Unit Options Granted:

Weighted average distribution yield	5.5%
Weighted average expected volatility	33.0%
Weighted average risk free interest rate	4.80%
Weighted average expected life	6 years
Weighted average contractual life	10 years
Weighted average of fair value of unit options granted	$ 7.45

A summary of the unit option activity for the year ended December 31, 2006 is provided below:

	Number of Units	Weighted Average Exercise Price
Outstanding, beginning of period	1,039,832	$ 18.88
Granted	286,403	34.62
Exercised	(304,936)	11.19
Forfeited	(95,143)	24.56
Outstanding, end of period	926,156	$ 25.70
Options exercisable at end of period	121,131	$ 23.58
Weighted average contractual term (years) end of period:		
Options outstanding	7.8	—
Options exercisable	7.5	—
Aggregate intrinsic value end of period (in thousands):		
Options outstanding	$ 13,107	—
Options exercisable	$ 1,970	—

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

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

CEI has one stock-based compensation plan, the Crosstex Energy, Inc. Long-Term Incentive Plan. Prior to September 6, 2006, the plan permitted the grant of awards covering an aggregate of 1,200,000 options for common stock and restricted shares. On September 6, 2006, CEI's board of directors adopted, subject to stockholder approval, an Amended and Restated Long-Term Incentive

Plan that increased the number of shares of common stock authorized for issuance under the plan to 1,530,000 shares. CEI's stockholders approved the plan on October 26, 2006. The plan is administered by the compensation committee of CEI's board of directors. The shares issued upon exercise or vesting are newly issued common shares.

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

Crosstex Energy, Inc. Restricted Shares:

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

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

No CEI stock options were granted to any officers or employees of the Partnership during 2006.

(7) Fair Value of Financial Instruments

The estimated fair value of the Partnership's financial instruments has been determined by the Partnership using available market information and valuation methodologies. Considerable judgment is required to develop the estimates of fair value; thus, the estimates provided below are not necessarily indicative of the amount the Partnership could realize upon the sale or refinancing of such financial instruments as of December 31, 2006 (in thousands):

	Carrying Value	Fair Value
Cash and cash equivalents	$ 825	$ 825
Trade accounts receivable and accrued revenues	367,023	367,023
Fair value of derivative assets	26,860	26,860
Note receivable	926	926
Accounts payable, drafts payable and accrued gas purchases	404,863	404,863
Current portion of long-term debt	10,012	10,012
Long-term debt	977,118	981,914
Fair value of derivative liabilities	14,699	14,699

The carrying amounts of the Partnership's cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the short-term maturities of these assets and liabilities. The carrying value for the note receivable approximates the fair value because this note earns interest based on the current prime rate.

The Partnership's long-term debt was comprised of borrowings under a revolving credit facility totaling $488.0 million as of December 31, 2006 that accrues interest under a floating interest rate structure. Accordingly, the carrying value of such indebtedness approximates fair value for the amounts outstanding under the credit facility. As of December 31, 2006, the Partnership also had borrowings totaling $498.5 million under senior secured notes with a weighted average interest rate of 6.76%. The fair value of these borrowings as of December 31, 2006 was adjusted to reflect to current market interest rate for such borrowings as of December 31, 2006.

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

(8) Derivatives

The Partnership manages its exposure to fluctuations in commodity prices by hedging the impact of market fluctuations. Swaps are used to manage and hedge prices and location risk related to these market exposures. Swaps are also used to manage margins on offsetting fixed-price purchase or sale commitments for physical quantities of natural gas and NGLs.

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

The fair value of derivative assets and liabilities, excluding the interest rate swap, are as follows as of December 31, 2006 (in thousands):

Fair value of derivative assets — current	$ 22,959
Fair value of derivative assets — long term	3,812
Fair value of derivative liabilities — current	(12,141)
Fair value of derivative liabilities — long term	(2,558)
Net fair value of derivatives	$ 12,072

Set forth below is the summarized notional amount and terms of all instruments held for price risk management purposes at December 31, 2006 (all quantities are expressed in British Thermal Units and liquids are expressed in gallons). The remaining term of the contracts extend no later than March 2008 for derivatives, excluding third-party on-system financial swaps, and extend to June 2010 for third-party on-system financial swaps. The Partnership’s counterparties to derivative contracts include BP Corporation, Total Gas & Power, Fortis, UBS Energy, Morgan Stanley and J. Aron & Co., a subsidiary of Goldman Sachs. Changes in the fair value of the Partnership’s derivatives related to third-party producers and customers gas marketing activities are recorded in earnings in the period the transaction is entered into. The effective portion of changes in the fair value of cash flow hedges is recorded in accumulated other comprehensive income until the related anticipated future cash flow is recognized in earnings and the ineffective portion is recorded in earnings.

	December 31, 2006			
Transaction type	Total Volume	Pricing Terms	Remaining Term of Contracts	Fair Value (In thousands)
Cash Flow Hedges:				
Natural gas swaps	171,000	NYMEX less a basis of $0.785 to NYMEX less a	January 2007 – June 2007	$ 73
Natural gas swaps	(3,117,000)	basis of $0.575 or fixed prices ranging from $8.20 to $10.855 settling against various Inside FERC Index prices	January 2007 – March 2008	6,191
Total natural gas swaps designated as cash flow hedges				$ 6,264
Liquids swaps	(26,747,768)	Fixed prices ranging from $0.61 to $1.6275 settling against Mt. Belvieu Average of daily postings (non-TET)	January 2007 – March 2008	$ 1,766

Transaction type	Total Volume	December 31, 2006 Pricing Terms	Remaining Term of Contracts	Fair Value (In thousands)
Total liquids swaps designated as cash flow hedges				$ 1,766
Mark to Market Derivatives:				
Swing swaps	1,685,625	Prices ranging from Inside FERC Index less $0.0275 to	January 2007	$ (2)
Swing swaps	(651,000)	Inside FERC Index plus $0.01 or a fixed price of $5.93 settling against various Gas Daily Index prices	January 2007	(12)
Total swing swaps				$ (14)
Physical offset to swing swap transactions	651,000	Prices of various Inside FERC Index prices settling against	January 2007	¾
Physical offset to swing swap transactions	(1,685,625)	various Gas Daily Index prices	January 2007	¾
Total physical offset to swing swaps				$ ¾
Basis swaps	31,040,000	NYMEX less a basis of $0.785 to NYMEX plus a	January 2007 – March 2008	$ (31)
Basis swaps	(31,414,000)	basis of $0.145 or prices ranging from $7.31 to $10.505 settling against various Inside FERC Index prices.	January 2007 – March 2008	(137)
Total basis swaps				$ (168)
Physical offset to basis swap transactions	5,090,000	Prices ranging from Inside FERC Index less $0.09 to	January 2007 – March 2007	$ (30,417)
Physical offset to basis swap transactions	(4,935,000)	Inside FERC Index plus $0.0175 or a fixed price of $7.31 settling against various Inside FERC Index prices	January 2007 – March 2007	30,891
Total physical offset to basis swap transactions				$ 474
Third party on-system financial swaps	8,415,800	Fixed prices ranging from $5.659 to $11.91 settling against various Inside FERC Index prices	January 2007 – June 2010	$ (9,420)
Total third party on-system financial swaps				$ (9,420)
Physical offset to third party on-system transactions	(8,415,800)	Fixed prices ranging from $5.71 to $11.96 settling against various Inside FERC Index prices	January 2007 – June 2010	$ 10,176
Total physical offset to third party on-system swaps				$ 10,176
Storage swap transactions:				
Storage swap transactions	(355,000)	Fixed price of $10.065 settling against Inside FERC Henry Hub Index price	February 2007	$ 1,333
Total financial storage swap transactions				$ 1,333
Natural gas liquid puts:				
Liquid put options (purchased)	80,497,830	Fixed prices ranging from $0.565 to $1.26 settling against Mount Belvieu	January 2007 – December 2007	$ 3,117
Liquid put options (sold)	(37,713,696)	Average Daily Index	January 2007 – December 2007	(1,456)
Total natural gas liquid puts				$ 1,661

On all transactions where the Partnership is exposed to counterparty risk, the Partnership analyzes the counterparty's financial condition prior to entering into an agreement, establishes limits, and monitors the appropriateness of these limits on an ongoing basis.

Assets and liabilities related to third party derivative contracts, swing swaps, storage swaps and puts are included in the fair value of derivative assets and liabilities and the profit and loss on the mark to market value of these contracts are recorded on a net basis as gain (loss) on derivatives in the consolidated statement of operations. The Partnership estimates the fair value of all of its energy trading contracts using actively quoted prices. The estimated fair value of energy trading contracts by maturity date was as follows (in thousands):

	Maturity Periods			
	Less Than One Year	One to Two Years	More Than Two Years	Total Fair Value
December 31, 2006	$ 3,872	$ 49	$ 121	$ 4,042

(9) Commitments and Contingencies

(a) Leases — Lessee

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

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

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

(b) Leases — Lessor

During 2006, the Partnership leased approximately 54 of its treating plants and 33 of its dew point control plants to customers under operating leases. The initial terms on these leases are generally 24 months, at which time the leases revert to 30-day cancelable leases. As of December 31, 2006, the Partnership only had 29 treating plants under operating leases with remaining non-cancelable lease terms in excess of one year. The future minimum lease rentals are $10.6 million and $6.7 million for the years ended December 31, 2007 and 2008, respectively. These leased treating plants have a cost of $35.0 million and accumulated depreciation of $6.6 million as of December 31, 2006.

(c) Employment Agreements

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

(d) Environmental Issues

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

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

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

(e) Other

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

(10) Segment Information

Identification of operating segments is based principally upon differences in the types and distribution channel of products. The Partnership's reportable segments consist of Midstream and Treating. The Midstream division consists of the Partnership's natural gas gathering and transmission operations and includes the south Louisiana processing and liquids assets, the processing and transmission assets located in north and south Texas, the pipelines and processing plants located in Louisiana, the Mississippi System, the Arkoma system in Oklahoma and various other small systems. Also included in the Midstream division are the Partnership's energy trading operations. The operations in the Midstream segment are similar in the nature of the products and services, the nature of the production processes, the type of customer, the methods used for distribution of products and services and the nature of the regulatory environment. The Treating division generates fees from its plants either through volume-based treating contracts or through fixed monthly payments. The Seminole carbon dioxide processing plant located in Gaines County, Texas is included in the Treating division.

The accounting policies of the operating segments are the same as those described in note 2 of the Notes to Consolidated Financial Statements. Corporate assets consist principally of property and equipment, including software, for general corporate support, working capital and debt financing costs.

The identifiable assets by segment as of December 31, 2006 are as follows (in thousands):

Midstream	$ 1,960,213
Treating	203,528
Corporate	30,734
Total	$ 2,194,475

(11) Condensed Consolidating Information

The following table presents the condensed consolidating balance sheet data for the General Partner and CELP as of December 31, 2006 (in thousands):

	General Partner	CELP	Consolidation Entries	Consolidated
Current assets	$ 1	$ 410,335	$ —	$ 410,336
Property, plant and equipment, net	—	1,105,813	—	1,105,813
Fair value of derivative assets	—	3,812	—	3,812
Intangible assets, net	—	638,602	—	638,602
Goodwill	—	24,495	—	24,495
Investment in CELP	20,472	—	(20,472)	—
Other assets, net	—	11,417	—	11,417
Total assets	$ 20,473	$ 2,194,474	$ (20,472)	$ 2,194,475
Current liabilities	$ —	$ 490,271	$ —	$ 490,271
Long-term debt	—	977,118	—	977,118
Deferred tax liability	—	8,996	—	8,996
Minority interest	—	3,654	691,405	695,059
Fair value of derivative liabilities	—	2,558	—	2,558
Partners' equity	20,473	711,877	(711,877)	20,473
Total liabilities and partners' equity	$ 20,473	$ 2,194,474	$ (20,472)	$ 2,194,475