Energy Transfer Partners, L.P.
Form 10-K
November 13, 2006

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

x **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended August 31, 2006

OR

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the Transition Period from ______ to ______

Commission file number 1-11727

ENERGY TRANSFER PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

Delaware	**73-1493906**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**

2838 Woodside Street, Dallas, Texas 75204

(Address of principal executive offices and zip code)

(214) 981-0700

(Registrant s telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of class	**Name of each exchange on which registered**
Common Units	New York Stock Exchange

Securities registered pursuant to section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes þ No ¨

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Yes ¨ No þ

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days.

Yes þ No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ¨

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Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer in Rule 12b-2 of the Exchange Act.

Large accelerated filer þ Accelerated filer ¨ Non accelerated filer ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).

Yes ¨ No þ

The aggregate market value as of February 28, 2006, of the registrant s Common Units held by non-affiliates of the registrant, based on the reported closing price of such units on the New York Stock Exchange on such date, was approximately $2,586,700,000. Common Units held by each executive officer and director and by each person who owns 5% or more of the outstanding Common Units have been excluded in that such persons may be deemed to be affiliates. This determination of affiliate status is not necessarily a conclusive determination for other purposes.

At November 1, 2006, the registrant had units outstanding as follows:

Energy Transfer Partners, L.P.	110,886,930 Common Units
	26,100,000 Class G Units
Documents Incorporated by Reference:	None

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ENERGY TRANSFER PARTNERS, L.P.

2006 FORM 10-K ANNUAL REPORT

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PART I

Forward-Looking Statements

Certain matters discussed in this report, excluding historical information, as well as some statements by us in periodic press releases and some oral statements of our officials during presentations about the Partnership, include certain forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. Statements using words such as anticipate, believe, intend, project, plan, expect , continue, estimate, goal, forecast, may, will, or similar expressio forward-looking statements. Although we and our General Partner believe such forward-looking statements are based on reasonable assumptions and current expectations and projections about future events, neither we or our General Partner can give assurances that such expectations will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. When considering forward-looking statements, please read the section titled Risk Factors included under Item 1A of this annual report.

ITEM 1. BUSINESS

Overview

We are one of the three largest publicly traded master limited partnerships in the United States in terms of market capitalization (approximately $5.4 billion as of October 31, 2006). We are engaged in the natural gas midstream and transportation and storage businesses through our operating subsidiary, La Grange Acquisition, L.P. (ETC OLP), and are a retail marketer of propane in the United States through our operating subsidiaries, Heritage Operating, L.P (HOLP) and Titan Energy Partners, L.P. We became a publicly traded master limited partnership in conjunction with an initial public offering as Heritage Propane Partners, L.P. (Heritage) in June 1996. In January 2004, we combined the natural gas midstream and transportation operations of ETC OLP with the retail propane operations of Heritage (the Energy Transfer Transactions). In March 2004, we changed our name to Energy Transfer Partners, L.P. (together with our subsidiaries, the Partnership or ETP).

Our midstream and transportation and storage businesses own and operate approximately 12,000 miles of in service natural gas gathering and transportation pipelines with an additional 600 miles under construction, three natural gas processing plants, two of which are currently connected to our gathering systems, fourteen natural gas treating facilities and three natural gas storage facilities located in Texas. Through ETC OLP, we conduct our natural gas midstream, transportation and storage businesses through two segments, the midstream segment and the transportation and storage segment. Our midstream segment focuses on the gathering, compression, treating, blending, processing and marketing of natural gas and our operations are currently concentrated in the Austin Chalk trend of southeast Texas, the Permian Basin of west Texas, the Barnett Shale in north Texas and the Bossier Sands in east Texas. Our transportation and storage segment focuses on the transportation of natural gas between major markets from various natural gas producing areas through connections with other pipeline systems as well as through our Oasis Pipeline, our East Texas Pipeline, our Fort Worth Basin Pipeline, our natural gas pipeline and storage assets that are referred to as the ET Fuel System, and our Houston Pipeline System, which are described below.

We are one of the three largest retail marketers of propane in the United States, serving more than one million customers from 442 customer service locations in 41 states. Our propane operations extend from coast to coast with concentrations in the western, upper midwestern, northeastern and southeastern regions of the United States.

For the year ended August 31, 2006, we had revenues of approximately $7.9 billion, operating income of approximately $642.9 million and net income of approximately $515.9 million.

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The following is a list of certain acronyms and terms generally used in the energy industry and throughout this document:

/d	per day
Bbls	barrels
Btu	British thermal unit, an energy measurement
Mcf	thousand cubic feet
MMBtu	million British thermal unit
MMcf	million cubic feet
Bcf	billion cubic feet
NGL	natural gas liquid, such as propane, butane and natural gasoline
Tcf	trillion cubic feet
LIBOR	London Interbank Offered Rate
NYMEX	New York Mercantile Exchange
Reservoir	A porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is separate from other reservoirs.

Energy Transfer Transactions

On January 20, 2004, Heritage and Energy Transfer Equity, L.P. (ETE), formerly known as La Grange Energy, L.P., completed a series of transactions whereby ETE contributed its subsidiary, ETC OLP, to Heritage in exchange for cash of $300.0 million less the amount of ETC OLP debt in excess of $151.5 million, less ETC OLP s accounts payable and other specified liabilities, plus agreed-upon capital expenditures paid by ETE relating to the ETC OLP business prior to closing, $433.9 million of Heritage Common and Class D Units, and the repayment of the ETC OLP debt of $151.5 million. These transactions and the other transactions described in the following paragraphs are referred to herein as the Energy Transfer Transactions. In conjunction with the Energy Transfer Transactions and prior to the contribution of ETC OLP to Heritage, ETC OLP distributed its cash and accounts receivables to ETE and an affiliate of ETE contributed an office building to ETC OLP. ETE also received 7,485,030 Special Units as consideration for the project it had in progress to construct the Bossier Pipeline now referred to as the East Texas Pipeline. The Special Units converted to Common Units upon the East Texas Pipeline becoming commercially operational and such conversion being approved by our Unitholders. The East Texas Pipeline became commercially operational on June 21, 2004, and the Unitholders approved the conversion of the Special Units at a special meeting held on June 23, 2004.

Simultaneously with the transactions described in the preceding paragraph, ETE obtained control of Heritage by acquiring all of the interests in Energy Transfer Partners GP, L.P. (ETP GP), formerly U.S. Propane, L.P., the General Partner of Heritage, and ETP GP s General Partner, Energy Transfer Partners, L.L.C., (ETP LLC) formerly U.S. Propane, L.L.C., from subsidiaries of AGL Resources, Inc., Atmos Energy Corporation, TECO Energy, Inc. and Piedmont Natural Gas Company, Inc. for $30.0 million (the General Partner Transaction). In conjunction with the General Partner Transaction, ETP GP contributed its 1.0101% General Partner interest in HOLP to Heritage in exchange for an additional 1% General Partner interest in Heritage. Simultaneously with these transactions, Heritage purchased the outstanding stock of Heritage Holdings, Inc. (Heritage Holdings) for $100.0 million.

Concurrent with the Energy Transfer Transactions, ETC OLP borrowed $325.0 million from financial institutions and Heritage raised $355.9 million of gross proceeds net of underwriter s discount through the sale of 18,400,000 Common Units at an offering price of $19.34 per unit. The net proceeds were used to finance the Energy Transfer Transactions and for general partnership purposes.

The above historical units and per unit offering price have been restated to reflect a two-for-one split effected March, 2005. See Note 6 - Partners Capital and Unit Based Compensation Plans of our consolidated financial statements for further discussion of the two-for-one split.

Recent Acquisitions and Expansions

On November 10, 2005, we acquired the remaining 2% limited partner interest in HPL Consolidation, L.P. (HPL) for $16.6 million in cash. (We purchased 98% of HPL in January 2005.) The purchase price was allocated to property, plant and equipment and the minority interest liability associated with the 2% limited partner interest was eliminated. As a result, HPL became a wholly-owned subsidiary of ETC OLP.

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Prior to November 2005, we owned a 50% interest in South Texas Gas Gathering, a joint venture that owned an 80% interest in the Dorado System, a 61-mile gathering system located in South Texas. We purchased the remaining 50% equity interest in South Texas Gas Gathering in November 2005 for $0.7 million.

On June 1, 2006, we acquired all the propane operations of Titan Energy Partners, LP and Titan Energy, GP LLC (collectively Titan) for cash of approximately $548.0 million, after working capital adjustments and net of cash acquired, and liabilities assumed of approximately $46.0 million. This acquisition was initially financed by borrowings under the ETP Revolving Credit Facility. Titan s propane assets primarily consist of retail propane operations in 33 states conducted from 146 district locations located in high growth areas of the U.S. The addition of the Titan assets expanded our retail propane operations into six additional states and several new operating territories in which we did not previously have operations. This expansion will further reduce the impact on the propane operations from weather patterns in any one area of the U.S., while continuing our focus on conducting the retail propane operations in attractive high-growth areas.

During the fiscal year ended August 31, 2006, HOLP and Titan collectively acquired substantially all of the assets of eight propane businesses. The aggregate purchase price for these acquisitions totaled $28.9 million.

In June 2006 we and Atmos Energy Corporation (Atmos) completed the North Side Loop (NSL) pipeline, a 45-mile, 30-inch pipeline system. The pipeline was constructed for the purpose of providing producers in the Ft. Worth Basin with pipeline capacity to reach markets on both Atmos and our pipeline systems. The pipeline will also provide a significant amount of supply for the growing demand for natural gas north of the Dallas/Fort Worth metroplex. The pipeline has a throughput capacity of 450 MMcf/d with the ability to expand with increased compression. We own 50% of the pipeline which cost $75.4 million to construct.

Other Developments

On August 31, 2006 we announced the completion of the first phase of our previously announced 42-inch pipeline construction project. This segment, comprised of 97 miles of 42-inch natural gas pipeline, connects our 30-inch pipeline in Freestone County, the Bethel Storage Facility and our 30-inch Texoma pipeline in Rusk County. This portion of the 42-inch project has been placed in service and is currently flowing natural gas. The completion of this first phase provides us with additional take-away capacity to transport gas out of the Barnett Shale and Bossier Sands producing areas.

The full benefit of our 42-inch construction project will be recognized upon completion of the additional phases, all of which are currently underway and are on schedule to be completed by March, 2007. Because of our increased transportation commitments, the Board of Directors approved a plan to upsize the recently announced 157-mile 36-inch expansion of this project to 42-inch for the section that runs from Limestone County, Texas to the interconnect with our Texoma pipeline, northeast of Beaumont. The increased upsizing will bring the estimated total cost of the project from $895.0 million to approximately $1.0 billion.

On September 15, 2006, we announced the execution of agreements with GE Energy Financial Services (GE) and Southern Union Company to acquire the Transwestern Pipeline, a 2,500 mile interstate natural gas pipeline. The agreements provide for a series of transactions in which we will acquire all of the member interests in CCE Holdings, LLC (CCEH) owned by GE and certain other investors. The member interests acquired will represent a 50% ownership in CCEH, which was formed in 2004 to purchase CrossCountry Energy. In the second transaction, CCEH will redeem our 50% ownership in CCEH in exchange for 100% ownership of Transwestern Pipeline Company, LLC (Transwestern), following which Southern Union will own all of the member interests of CCEH. On November 1, 2006, we acquired the member interests in CCEH from GE and certain other investors for $1 billion and expect to complete the remaining series of transactions in the second quarter of fiscal year 2007. Upon closing we expect the acquisition to be immediately accretive to our Common Unitholders. We financed the purchase price with our issuance of approximately 26.1 million Class G Units issued to ETE simultaneous with the closing on November 1, 2006.

The Transwestern Pipeline connects supply areas in the San Juan Basin in southern Colorado and northern New Mexico, the Anadarko Basin in the Mid-continent and the Permian Basin in west Texas to markets in the Midwest, Texas, Arizona, New Mexico and California. The Transwestern Pipeline interconnects with our existing intrastate pipelines in west Texas. The combination of pipeline systems will result in new market opportunities for existing natural gas supply sources on both systems and increases supply availability and flexibility to existing markets served by both systems.

On October 3, 2006, we announced that we entered into a long-term agreement with CenterPoint Energy Resources Corp (CenterPoint) to provide the natural gas utility with firm transportation and storage services on our HPL System located along the Texas gulf coast region. Under the terms of this agreement, CenterPoint has contracted for 129 Bcf per year of firm transportation capacity combined with 10 Bcf of working gas storage capacity in our Bammel Storage facility. Under the new agreement with CenterPoint, we will no longer need to utilize predominately all of the Bammel Storage facility s working gas capacity for the supplying of CenterPoint s winter needs. This will reduce our working capital requirements that were necessary to finance the working gas while in storage and will provide us an opportunity to offer storage to third parties. This agreement goes into effect beginning April 1, 2007.

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On September 20, 2006, we announced two internal growth projects:

- a natural gas processing facility in Johnson County, Texas. The processing facility is being built in two phases to process rich natural gas produced from the Barnett Shale and will connect with our existing pipeline infrastructure. Phase I consists of a cryogenic gas plant with capacity of 115 MMcf/d, which is expected to be in service by the end of November 2006. Phase II of the project includes another 170 MMcf/d cryogenic gas plant and a 100 MMcf/d hydrocarbon dew point refrigeration plant, and is expected to be completed by the end of June 2007. The facility is being built to accommodate additional expansion in the future. This facility will be one of the few North Texas natural gas processing plants with access to two NGL pipelines. The estimated cost for this project is approximately $65.0 million; and

- a 36-inch pipeline expansion connecting the Barnett Shale to our 30-inch Texoma pipeline. The 36-inch pipeline expansion is the result of our continued success in contracting transportation volumes. This 135-mile pipeline connects our existing Forth Worth Basin system to our 30-inch Texoma pipeline in Lamar County, Texas. The project expands producers options by providing additional market opportunities including access to the Carthage hub, interstate pipelines and industrial users along the Houston Ship Channel. It includes 27 miles of 30-inch pipe, 108 miles of 36-inch pipe and 64,000 horsepower of compression with an initial capacity of 700 MMcf/d with expansion capabilities up to 1.0 Bcf/d. This project will cost approximately $300.0 million to construct.

In September 2006 we also acquired two small gathering systems in east and north Texas for an aggregate purchase price of $30.0 million. The purchase and sale agreement for the gathering system in north Texas also has a contingent payment not to exceed $25.0 million to be determined eighteen months from the closing date. These systems provide us with additional capacity in the Barnett Shale and in the Travis Peak area of east Texas.

ETC OLP (Midstream and Transportation and Storage Operations)

The following map depicts our natural gas pipeline and storage systems:

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Our midstream segment consists of the following:

- The Southeast Texas System, a 4,250-mile integrated system located in southeast Texas that gathers, compresses, treats, processes and transports natural gas from the Austin Chalk trend. The Southeast Texas System is a large natural gas gathering system covering thirteen counties between Austin and Houston. The system includes the La Grange processing plant, the Madison processing plant, and seven treating facilities. This system is connected to the Katy Hub through the 55-mile Katy Pipeline and is also connected to the Oasis Pipeline, as well as two power plants.

The La Grange and Madison processing plants are cryogenic natural gas processing plants that process the rich natural gas that flows through our system to produce residue gas and NGLs. The plants have a processing capacity of approximately 320 MMcf/d. Our seven treating facilities have an aggregate capacity of 730 MMcf/d. These treating facilities remove carbon dioxide and hydrogen sulfide from natural gas gathered into our system before the natural gas is introduced to transportation pipelines to ensure that the gas meets pipeline quality specifications.

- Interests in various midstream assets located in Texas and Louisiana, including the Vantex System, the Rusk County Gathering System, the Whiskey Bay System, and the Chalkley Transmission System. On a combined basis, these assets have a capacity of approximately 560 MMcf/d.

- Marketing operations through our producer services business, in which we market the natural gas that flows through our assets, referred to as on-system gas, and attract other customers by marketing volumes of natural gas that do not move through our assets, referred to as off-system gas. For both on-system and off-system gas, we purchase natural gas from natural gas producers and other supply points and sell the natural gas to utilities, industrial consumers, other marketers and pipeline companies, thereby generating gross margins based upon the difference between the purchase and resale prices.

Substantially all of our on-system marketing efforts involve natural gas that flows through either the Southeast Texas System or our transportation pipelines. For the off-system gas, we purchase gas or act as an agent for small independent producers that do not have marketing operations. We develop relationships with natural gas producers to facilitate the purchase of their production on a long-term basis. We believe that this business provides us with strategic insight and market intelligence, which may impact our expansion and acquisition strategy.

Our transportation and storage segment consists of the following:

- The Oasis Pipeline, a 583-mile natural gas pipeline that directly connects the Waha Hub to the Katy Hub. The Oasis Pipeline is primarily a 36-inch diameter natural gas pipeline. It has bi-directional capability with approximately 1.2 Bcf/d of throughput capacity moving west-to-east and greater than 750 MMcf/d of throughput capacity moving east-to-west. The Oasis Pipeline has many interconnections with other pipelines, power plants, processing facilities, municipalities and producers.

The Oasis Pipeline is integrated with our Southeast Texas System and is an important component to maximizing our Southeast Texas System s profitability. The Oasis Pipeline enhances the Southeast Texas System by:

- providing us with the ability to bypass the La Grange processing plant when processing margins are unfavorable;

- providing access for natural gas on the Southeast Texas System to other third party supply and market points and interconnecting pipelines; and allowing us to bypass our treating facilities on the Southeast Texas System and blend untreated natural gas from the Southeast Texas System with gas on the Oasis Pipeline while continuing to meet pipeline quality specifications.

The ET Fuel System, which serves some of the most active drilling areas in the United States, is comprised of approximately 2,100 miles of intrastate natural gas pipeline and related natural gas storage facilities. With approximately 460 receipt and/or delivery points, including interconnects with pipelines providing direct access to power plants and interconnects with other intrastate and interstate pipelines, the ET Fuel System is strategically located near high-growth production areas and provides access to the Waha Hub, the Katy Hub and the Carthage Hub, the three major natural gas trading centers in Texas. The ET Fuel System has total system throughput capacity of approximately 1.3 Bcf/d of natural gas and total working storage capacity of 12.4 Bcf of natural gas. The ET Fuel System operates our Bethel natural gas storage facility, with a working capacity of 6.4 Bcf, an average withdrawal capacity of 300 MMcf/d and an injection capacity of 75 MMcf/d, and our Bryson

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natural gas storage facility, with a working capacity of 6.0 Bcf, an average withdrawal capacity of 120 MMcf/d and an average injection capacity of 96 MMcf/d. Integrated into our ET Fuel System is our Fort Worth Basin Pipeline, which became operational on May 26, 2005. The Fort Worth Basin Pipeline is a 55-mile, 24-inch natural gas pipeline that connects our existing pipelines in north Texas and provides transportation for natural gas production from the Barnett Shale producing area. The completion of the Fort Worth Basin Pipeline is the first part of our previously disclosed expansion program that was implemented to integrate our 36-inch Katy Pipeline and the Southeast Texas System assets with the ET Fuel System and the Houston Pipeline System.

The East Texas Pipeline is a 148-mile natural gas pipeline that connects three treating facilities, one of which we own, with our Southeast Texas System. This pipeline was the first phase of a multi-phased project that increased service to producers in East and North Central Texas and provided access to the Katy Hub. The East Texas Pipeline expansion had an initial capacity of over 400 MMcf/d which increased to the current capacity of 675 MMcf/d with the addition of the Grimes County Compressor Station. Over 500 MMcf/d of pipeline capacity is contracted under long-term agreements with XTO Energy Inc. and other producers.

The Houston Pipeline System is comprised of approximately 4,200 miles of intrastate natural gas pipeline with an aggregate capacity of 2.4 Bcf/d, the underground Bammel storage reservoir and related transportation assets. The system has access to multiple sources of historically significant natural gas supply reserves from south Texas, the Gulf Coast of Texas, east Texas and the western Gulf of Mexico, and is directly connected to major gas distribution, electric and industrial load centers in Houston, Corpus Christi, Texas City and other cities located along the Gulf Coast of Texas. The Houston Pipeline System is well situated to gather gas in many of the major gas producing areas in Texas and has a particularly strong presence in the key Houston Ship Channel and Katy Hub markets, which significantly contributes to our overall ability to play an important role in the Texas natural gas markets. The Houston Pipeline System is also well positioned to capitalize upon off-system opportunities due to its numerous interconnections with other pipeline systems, its direct access to multiple market hubs at Katy, the Houston Ship Channel and Agua Dulce, and our operation of the Bammel storage facility. The Bammel storage facility has a total working gas capacity of approximately 65 Bcf and has a peak withdrawal rate of 1.3 Bcf/d. The field also has considerable flexibility during injection periods in that the Houston Pipeline System has engineered an injection well configuration to provide for a 0.6 Bcf/d peak injection rate. The Bammel storage facility is strategically located near the Houston Ship Channel market area and the Katy Hub and is ideally suited to provide a physical backup for on-system and off-system customers.

Heritage Operating, L.P. and Titan Operating, L.P.

Through HOLP and Titan, we are one of the three largest retail propane marketers in the United States, based on gallons sold. We serve more than one million customers from 442 customer service locations in 41 states. Our propane operations extend from coast to coast with concentrations in the western, upper midwestern, northeastern and southeastern regions of the United States. We are also a wholesale propane supplier in the southwestern and southeastern United States and in Canada, the latter through participation in M-P Energy Partnership. M-P Energy Partnership is a Canadian partnership in which we own a 60% interest that is engaged in wholesale distribution and in supplying our northern U.S. locations. Our propane business has grown primarily through acquisitions of retail propane operations and, to a lesser extent, through internal growth.

Following is a summary of the retail sales volumes per fiscal year for the last three fiscal years:

	For the Years Ended August 31,			
	2006	2005	2004 (Actual)	2004 (Aggregate)
Retail Gallons Sold (in millions)	429.1	406.3	226.2	397.9

We present retail gallons sold for fiscal year 2004 on the basis of (1) an aggregate total reflecting Heritage s historical results from September 1, 2003 until the closing of the Energy Transfer Transactions on January 19, 2004, and (2) Heritage s historical results reflecting the actual results for the fiscal year ended August 31, 2004, for comparability purposes only. The aggregate information is not necessarily indicative of the results of operations that would have occurred had the transactions been made at the beginning of the periods presented or the future results of the combined operations.

For the year ended August 31, 2006, the retail gallons sold include 24.5 million gallons of retail sales volumes for Titan for the period from the date we acquired Titan (June 1, 2006) through August 31, 2006.

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Business Strategy

Our business strategy is to increase Unitholder distributions and the value of our Common Units. We believe we have engaged, and will continue to engage, in a well-balanced plan for growth through acquisitions, internally generated expansion, and measures aimed at increasing the profitability of our existing assets.

We intend to continue to operate as a diversified, growth-oriented master limited partnership with a focus on increasing the amount of cash available for distribution on each Common Unit. We believe that by pursuing independent operating and growth strategies for our midstream, transportation and storage and propane businesses, we will be best positioned to achieve our objectives.

We expect that acquisitions in our midstream and transportation and storage segments will be the primary focus of our acquisition strategy going forward as evidenced by the recently announced plan to acquire the Transwestern Pipeline system, although we will also continue to pursue complementary propane acquisitions as evidenced by our acquisition of Titan in June 2006. We also anticipate that our midstream and transportation and storage business will provide internal growth projects of greater scale compared to those available in our propane business as demonstrated by our 42-inch pipeline project and other recently announced projects.

Midstream and Transportation and Storage Business Strategies

Enhance profitability of existing assets. We intend to increase the profitability of our existing asset base by adding new volumes of natural gas, undertaking additional initiatives to enhance utilization and reducing costs by improving operations.

Engage in construction and expansion opportunities. We intend to leverage our existing infrastructure and customer relationships by constructing and expanding systems to meet new or increased demand for midstream services. These projects include those discussed above and include the construction of the 42-inch pipeline project, the natural gas processing facility in Johnson County, Texas, and our 36-inch pipeline expansion connecting the Barnett Shale to our 30-inch Texoma pipeline. We expect that these expansions will lead to additional growth opportunities in this area.

Increase cash flow from fee-based businesses in our midstream segment. Excluding results from our marketing activities, the portion of our gross margin in the midstream segment attributable to fee-based business has continued to increase. We charge fees for providing midstream services, including gathering, compressing, treating, processing and transmitting natural gas for producers. These fee-based services are dependent on throughput volume and are typically less affected by short-term changes in commodity prices. We intend to seek to increase the percentage of our midstream business conducted with third parties under fee-based arrangements in order to reduce our exposure to changes in the prices of natural gas and NGLs.

Growth through acquisitions. As demonstrated by our acquisitions of the gathering systems in north and east Texas and the recent announcement of the Transwestern Pipeline acquisition, we intend to make strategic acquisitions of midstream, transportation and storage assets in our current areas of operation that offer the opportunity for operational efficiencies and the potential for increased utilization and expansion of our existing and acquired assets. We will also pursue midstream, transportation and storage asset acquisition opportunities in other regions of the U.S. with significant natural gas reserves and high levels of drilling activity or with growing demand for natural gas. We believe that we will be well positioned to benefit from any additional acquisition opportunities that may arise as a result of the ongoing divestiture of midstream assets by large industry participants.

Propane Business Strategies

Pursue internal growth opportunities. In addition to pursuing expansion through acquisitions, we have aggressively focused on high return internal growth opportunities at our existing customer service locations. We believe that by concentrating our operations in areas experiencing higher-than-average population growth, we are well positioned to achieve internal growth by adding new customers.

Growth through complementary acquisitions. We believe that our position as one of the three largest propane marketers in the United States provides us a solid foundation to continue our acquisition growth strategy through consolidation. We believe that the fragmented nature of the propane industry will continue to provide opportunities for growth through the acquisition of propane businesses that complement our existing asset base. In addition to

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focusing on propane acquisition candidates in our existing areas of operations, we will also consider core acquisitions in other higher-than-average population growth areas in which we have no presence in order to further reduce the impact adverse weather patterns and economic downturns in any one region could have on our overall operations.

Maintain low-cost, decentralized operations. We focus on controlling costs, and we attribute our low overhead costs primarily to our decentralized structure. By delegating all customer billing and collection activities to the customer service location level, as well as delegating other responsibilities to the operating level, we have been able to operate without a large corporate staff. In addition, our customer service location level incentive compensation program encourages employees at all levels to control costs while increasing revenues.

Competitive Strengths

We believe that we are well-positioned to compete in both the natural gas midstream and transportation and storage and propane industries based on the following strengths:

Our enhanced access to capital and financial flexibility will allow us to compete more effectively in acquiring assets and expanding our systems. We expect that our credit facility and our recent financing transactions increase our financial flexibility and enhance our access to capital. We believe this will allow us to implement our operating strategies in a timely manner and more effectively compete in acquiring additional assets or expanding our existing systems.

Our experienced management team has an established reputation as highly-effective, strategic operators within our operating segments. In the past, the management teams of each of our operating segments have been successful in identifying and consummating strategic acquisitions that enhance our businesses. In addition, our management team has a substantial equity ownership in us and is motivated through performance-based incentive compensation programs to effectively and efficiently manage our business operations.

Midstream and Transportation and Storage Business Strengths

We have a significant market presence in each of our operating areas. We have a significant market presence in each of our operating areas, which are located in major natural gas producing regions of the United States. We expect the acquisition of Transwestern Pipeline will provide us with market presence in other prolific gas-producing regions in the western United Sates.

Our assets provide marketing flexibility through our access to numerous markets and customers. The combination of our Oasis Pipeline and our Southeast Texas System provides our customers direct access to the Waha and Katy Hubs and to virtually all other market areas in the United States via interconnections with major intrastate and interstate natural gas pipelines. Furthermore, our Oasis Pipeline is tied directly or indirectly to a number of major power generation facilities in Texas as well as several industrial and utility end-users. With the acquisition of the ET Fuel System in June 2004, the HPL acquisition in January 2005, and the completion of the East Texas Pipeline system and the Fort Worth Basin pipeline, we have also increased our access to additional power plants, industrial users, municipalities, and co-operatives, and the added storage facilities add flexibility for fuel management services. The completion of the 42-inch pipeline project and other related projects will provide producers with firm capacity out of the Barnett Shale and other major producing areas to all major market hubs in Texas and numerous interstate pipelines. We also expect to provide producers with additional firm capacity once we complete the acquisition of Transwestern Pipeline.

Our Southeast Texas System has additional capacity, which provides opportunities for higher levels of utilization. We expect to connect new supplies of natural gas volumes by utilizing the available capacity on the Southeast Texas System. The available capacity also provides us with opportunities to extend the Southeast Texas System to additional natural gas producing areas, such as east Texas, through the East Texas Pipeline.

Our ability to bypass our La Grange processing plant reduces our commodity price risk. A significant benefit of our ownership of the Oasis Pipeline is that we can elect not to process natural gas at our La Grange processing plant when processing margins (or the difference between NGL sales prices and the cost of natural gas) are unfavorable. Instead of processing the natural gas, we are able to deliver natural gas meeting pipeline quality specifications by blending rich gas, or gas with a high NGL content, from the Southeast Texas System with lean gas, or gas with a low

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NGL content, transported on the Oasis Pipeline. This enables us to sell the blended natural gas for a higher price than we would have been able to realize upon the sale of NGLs if we had to process the natural gas to extract NGLs.

The Houston Pipeline System enables us to engage in natural gas storage transactions in which we seek to find and profit from pricing differences that occur over time. The Bammel natural gas storage facility, acquired when we purchased the Houston Pipeline System, has a total working gas capacity of approximately 65 Bcf. The reservoir has a peak withdrawal rate of 1.3 Bcf/d and also has considerable flexibility during injection periods in that the Houston Pipeline System has engineered an injection well configuration to provide for a 600 MMcf/d peak injection rate. Therefore, we are able to purchase physical natural gas and then sell financial contracts at a price sufficient to cover our carrying costs and provide for a gross profit margin. In addition, the Bammel natural gas storage facility is strategically located near the Houston Ship Channel market area and the Katy Hub and is ideally suited to provide a physical backup for on-system and off-system customers.

Propane Business Strengths

Geographically diverse retail propane network. We believe our geographically diverse network of retail propane assets reduces our exposure to unfavorable weather patterns and economic downturns in any one geographic region, thereby reducing the volatility of our cash flows.

Experience in identifying, evaluating and completing acquisitions. We follow a disciplined acquisition strategy that concentrates on propane companies that (1) are located in geographic areas experiencing higher-than-average population growth, (2) provide a high percentage of sales to residential customers, (3) have a strong reputation for quality service, and (4) own a high percentage of the propane tanks used by their customers. In addition, we attempt to capitalize on the reputations of the companies we acquire by maintaining local brand names, billing practices and employees, thereby creating a sense of business continuity which minimizes customer loss. We believe that this strategy has also helped to make us an attractive buyer for many propane acquisition candidates from a seller s viewpoint.

Operations that are focused in areas experiencing higher-than-average population growth. We believe that our concentration in higher-than-average population growth areas provides a strong economic foundation for expansion through acquisitions and internal growth. We do not believe that we are more vulnerable than our competitors to displacement by natural gas distribution systems because the majority of our areas of operations are located in rural areas where natural gas is not readily available.

Low-cost administrative infrastructure. We are dedicated to maintaining a low-cost operating profile and have a successful track record of aggressively pursuing opportunities to reduce costs. Of our 3,890 full-time propane employees as of October 13, 2006, only 173, or approximately 4.5%, were general and administrative.

Decentralized operating structure and entrepreneurial workforce. We believe that our decentralized propane operations foster an entrepreneurial corporate culture by: (1) having operational decisions made at the customer service location and operating level, (2) retaining billing, collection and pricing responsibilities at the local and operating level, and (3) rewarding employees for achieving financial targets at the local level.

Midstream Natural Gas Industry Overview

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

Natural gas has widely varying quality and composition, depending on the field, the formation or the reservoir from which it is produced. The principal constituents of natural gas are methane and ethane, though most natural gas also contains varying amounts of heavier components, such as propane, butane and natural gasoline, that may be removed by a number of processing methods. Most raw materials produced at the wellhead are not suitable for long-haul pipeline transportation or commercial use and must be compressed, transported via pipeline to a central processing facility, and then processed to remove the heavier hydrocarbon components and other contaminants that would interfere with pipeline transportation or the end use of the gas.

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Demand for natural gas. Natural gas continues to be a critical component of energy consumption in the United States. According to the Energy Information Administration, or the EIA, in its 2006 annual outlook, total domestic consumption of natural gas is expected to increase by over 0.7% per annum from an estimated 22.4 Tcf consumed in 2004 to 26.9 Tcf in 2030. During the five-year period ended December 31, 2005, the United States has on average consumed approximately 22.4 Tcf per year, with average domestic production of approximately 18.9 Tcf per year during the same period. The industrial and electricity generation sectors currently account for the largest usage of natural gas in the United States.

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

Natural gas compression. Gathering systems are operated at design pressures that will maximize the total throughput from all connected wells. Specifically, lower pressure gathering systems allow wells, which produce at progressively lower field pressures as they age, to remain connected to gathering systems and to continue to produce for longer periods of time. As the pressure of a well declines, it becomes increasingly more difficult to deliver the remaining production in the ground against a higher pressure that exists in the connecting gathering system. Field compression is typically used to lower the pressure of a gathering system. If field compression is not installed, then the remaining production in the ground will not be produced because it cannot overcome the higher gathering system pressure. In contrast, if field compression is installed, then a well can continue delivering production that otherwise would not be produced.

Natural gas treating. Natural gas has a varied composition depending on the field, the formation and the reservoir from which it is produced. Natural gas from certain formations is higher in carbon dioxide, hydrogen sulfide or certain other contaminants. Treating plants remove carbon dioxide and hydrogen sulfide from natural gas to ensure that it meets pipeline quality specifications.

Natural gas processing. Some natural gas produced by a well does not meet the pipeline quality specifications established by downstream pipelines or is not suitable for commercial use and must be processed to remove the mixed NGL stream. In addition, some natural gas produced by a well, while not required to be processed, can be processed to take advantage of favorable processing margins. Natural gas processing involves the separation of natural gas into pipeline quality natural gas, or residue gas, and a mixed NGL stream.

Natural gas transportation. Natural gas transportation pipelines receive natural gas from other mainline transportation pipelines and gathering systems and deliver the natural gas to industrial end-users, utilities and other pipelines.

Propane Industry Overview

Propane, a by-product of natural gas processing and petroleum refining, is a clean-burning energy source recognized for its transportability and ease of use relative to alternative forms of stand-alone energy sources. Retail propane use falls into three broad categories: (1) residential applications, (2) industrial, commercial and agricultural applications and (3) other retail applications, including motor fuel sales. In our wholesale operations, we sell propane principally to governmental agencies and industrial end-users.

Propane is extracted from natural gas at processing plants or separated from crude oil during the refining process. Propane is normally transported and stored in a liquid state under moderate pressure or refrigeration for ease of handling in shipping and distribution. When the pressure is released or the temperature is increased, it is usable as a flammable gas. Propane is naturally colorless and odorless. An odorant is added to allow its detection. Like natural gas, propane is a clean burning fuel and is considered an environmentally preferred energy source.

Propane competes with other sources of energy, some of which are less costly for equivalent energy value. We compete for customers against suppliers of electricity, natural gas and fuel oil. Competition from alternative energy sources has been increasing as a result of reduced utility regulation. Except for certain industrial and commercial applications, propane is generally not competitive with natural gas in areas where natural gas pipelines already exist because natural gas is a significantly less expensive source of energy than propane. The gradual expansion of natural gas distribution systems in the United States has resulted in the availability of natural gas in many areas that previously depended upon propane. Although the extension of natural gas pipelines tends to displace propane distribution in areas affected, we believe that new opportunities for propane sales arise as more geographically

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remote neighborhoods are developed. Even though propane is similar to fuel oil in certain applications and market demand, propane and fuel oil compete to a lesser extent primarily because of the cost of converting from one to another. According to industry publications, propane accounts for 6 1/2% of household energy consumption in the United States.

In addition to competing with alternative energy sources, we compete with other companies engaged in the retail propane distribution business. Competition in the propane industry is highly fragmented and generally occurs on a local basis with other large multi-state propane marketers, thousands of smaller local independent marketers and farm cooperatives. Most of our customer service locations compete with five or more marketers or distributors in their area of operations. Each retail distribution outlet operates in its own competitive environment because retail marketers tend to locate in close proximity to customers. The typical retail distribution outlet generally has an effective marketing radius of approximately 50 miles, although in certain rural areas the marketing radius may be extended by satellite locations.

The ability to compete effectively further depends on the reliability of service, responsiveness to customers and the ability to maintain competitive prices. We believe that our safety programs, policies and procedures are more comprehensive than many of our smaller, independent competitors and give us a competitive advantage over such retailers.

The wholesale propane business is highly competitive. For fiscal year 2006, our domestic wholesale operations (excluding M-P Energy Partnership) accounted for only 3.6% of our total gallons sold in the United States and approximately .86% of our gross profit. We do not emphasize wholesale operations, but believe that limited wholesale activities enhance our ability to supply our retail operations.

The Midstream and Transportation and Storage Segments

Competition

The business of providing natural gas gathering, transmission, treating, transporting, storing and marketing services is highly competitive. Since pipelines are generally the only practical mode of transportation for natural gas over land, the most significant competitors of our transportation and storage segment are other pipelines. Pipelines typically compete with each other based on location, capacity, price and reliability.

We face competition with respect to retaining and obtaining significant natural gas supplies under terms favorable to us for the gathering, treating and marketing portions of our business. Our competitors include major integrated oil companies, interstate and intrastate pipelines and companies that gather, compress, treat, process, transport and market natural gas. Many of our competitors, such as major oil and gas and pipeline companies, have capital resources and control supplies of natural gas substantially greater than ours.

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

Credit Risk and Customers

We have a concentration of customers in natural gas transmission, distribution and marketing as well as industrial end-users and customers in the refining and petrochemical industries. We are diligent in attempting to ensure that we issue credit to credit-worthy customers. However, our purchase and resale of gas exposes us to significant credit risk, as the margin on any sale is generally a very small percentage of the total sale price. Therefore, a credit loss can be very large relative to our overall profitability.

During the year ended August 31, 2006 none of our customers individually accounted for more than 10% of our midstream and transportation and storage segment revenues.

Regulation

Regulation by FERC of Interstate Natural Gas Pipelines. Under the Natural Gas Act (NGA), the Federal Energy Regulatory Commission (FERC) generally regulates the transportation of natural gas in interstate commerce. For FERC regulatory purposes, transportation service includes storage service. Currently, we do not own any

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interstate natural gas transportation facilities, so FERC does not directly regulate any of our pipeline operations pursuant to its jurisdiction under the NGA. However, FERC s regulation influences certain aspects of our business and the market for our products. In general, FERC has authority over natural gas companies that provide natural gas pipeline transportation services in interstate commerce and its authority to regulate those services includes:

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

Failure to comply with the NGA can result in the imposition of administrative, civil and criminal remedies.

In recent years, FERC has pursued pro-competitive policies in its regulation of interstate natural gas pipelines. However, we cannot assure you that FERC will continue this approach as it considers matters such as pipelines rates and rules and policies that may affect rights of access to natural gas transportation capacity.

In connection with our announcement to acquire the Transwestern Pipeline, we will be regulated by the FERC as the Transwestern Pipeline transports natural gas in interstate commerce.

Intrastate Pipeline Regulation. Our intrastate natural gas pipeline operations generally are not subject to rate regulation by FERC, but they are subject to regulation by various agencies in Texas, principally the Texas Railroad Commission (TRRC), where they are located. However, to the extent that our intrastate pipeline systems transport natural gas in interstate commerce, the rates, terms and conditions of such transportation service are subject to FERC jurisdiction under Section 311 of the Natural Gas Policy Act (NGPA), which regulates, among other things, the provision of transportation services by an intrastate natural gas pipeline on behalf of a local distribution company or an interstate natural gas pipeline. Under Section 311, rates charged for transportation must be fair and equitable, and amounts collected in excess of fair and equitable rates are subject to refund with interest, and the terms and conditions of service set forth in the pipeline s statement of operating conditions are subject to FERC review and approval. Failure to observe the service limitations applicable to transportation and storage services under Section 311, failure to comply with the rates approved by FERC for Section 311 service, and failure to comply with the terms and conditions of service established in the pipeline s FERC approved Statement of Operating Conditions could result in an alteration of jurisdictional status, and/or the imposition of administrative, civil and criminal remedies.

Our intrastate pipeline and storage operations in Texas are subject to the Texas Utilities Code, as implemented by the TRRC. Generally, the TRRC is vested with authority to ensure that rates, operations and services of gas utilities, including intrastate pipelines, are just and reasonable and not discriminatory. The TRRC has authority to ensure that rates charged by intrastate pipelines for natural gas sales or transportation services are just and reasonable. The rates we charge for transportation services are deemed just and reasonable under Texas law unless challenged in a complaint. We cannot predict whether such a complaint will be filed against us or whether the TRRC will change its regulation of these rates. Failure to comply with the Texas Utilities Code can result in the imposition of administrative, civil and criminal remedies.

Sales of Natural Gas. Sales for resale of natural gas in interstate commerce made by intrastate pipelines or their affiliates are subject to FERC regulation unless the gas is produced by the pipeline or affiliate. Under current federal rules, however, the price at which we sell natural gas currently is not regulated, insofar as the interstate market is concerned and, for the most part, is not subject to state regulation. Effective as of January 12, 2004, the FERC s rules require pipelines (including intrastate pipelines) and their affiliates who sell gas in interstate commerce subject to FERC s jurisdiction to adhere to a code of conduct prohibiting market manipulation and transactions that have no legitimate business purpose or result in prices not reflective of legitimate forces of supply and demand. Those who violate such code of conduct may be subject to suspension or loss of authorization to perform such sales, disgorgement of unjust profits, or other appropriate non-monetary remedies imposed by FERC. FERC denied rehearing of these rules on May 19, 2004, but the rules are still subject to possible court appeals. We cannot predict the outcome of these further proceedings, but do not believe we will be affected materially differently from other intrastate gas pipelines and their affiliates. In addition, our sales of natural gas are affected by the availability, terms and cost of pipeline transportation. As noted above, the price and terms of access to pipeline transportation are

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subject to extensive federal and state regulation. FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transmission companies that remain subject to FERC s jurisdiction. These initiatives also may affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry and these initiatives generally reflect more light-handed regulation. We cannot predict the ultimate impact of these regulatory changes to our natural gas marketing operations, and we note that some of FERC s more recent proposals may adversely affect the availability and reliability of interruptible transportation service on interstate pipelines. We do not believe that we will be affected by any such FERC action materially differently than other natural gas marketers with whom we compete.

Gathering Pipeline Regulation. Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of FERC under the NGA. We own a number of natural gas pipelines in Texas and Louisiana that we believe meet the traditional tests FERC has used to establish a pipeline s status as a gatherer not subject to FERC jurisdiction. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of substantial, on-going litigation, so the classification and regulation of our gathering facilities could be subject to change based on future determinations by FERC and the courts. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements and in some instances complaint-based rate regulation.

In Texas, our gathering facilities are subject to regulation by the TRRC under the Texas Utilities Code in the same manner as described above for our intrastate pipeline facilities. Louisiana s Pipeline Operations Section of the Department of Natural Resources Office of Conservation is generally responsible for regulating intrastate pipelines and gathering facilities in Louisiana and has authority to review and authorize natural gas transportation transactions and the construction, acquisition, abandonment and interconnection of physical facilities. Historically, apart from pipeline safety, Louisiana has not acted to exercise this jurisdiction respecting gathering facilities. Our Chalkley System is regulated as an intrastate transporter, and the Office of Conservation has determined that our Whiskey Bay System is a gathering system.

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

Natural gas gathering may receive greater regulatory scrutiny at both the state and Federal levels and a number of such companies have transferred gathering facilities to unregulated affiliates. For example, the TRRC has approved changes to its regulations governing transportation and gathering services performed by intrastate pipelines and gatherers, which prohibit such entities from unduly discriminating in favor of their affiliates. Many of the producing states have adopted some form of complaint-based regulation that generally allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering access and rate discrimination allegations. Our gathering operations could be adversely affected should they be subject in the future to the application of additional or different state or federal regulation of rates and services. Our gathering operations also may be or become subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

As part of industry-wide inquiries into the natural gas market disruptions occurring around the times of the hurricanes of late 2005, we have participated in discussions with, and have provided information to, industry regulators concerning transactions by our subsidiaries during our fiscal 2006 first and second quarters. We believe, after due inquiry, that our transactions complied in all material respects with applicable rules and regulations. These regulatory inquiries have not yet been concluded. While we are unable to predict the final outcome of these inquiries, management believes it is probable that the industry regulators will require a payment in order to conclude the inquiries. Accordingly, management has provided an accrual as of August 31, 2006 for our best estimate of the payment amount that will be required to conclude these inquiries in a negotiated settlement process. We do not expect that any expenditures incurred in connection therewith in excess of the accrual provided as of August 31, 2006 will have a material impact on our financial condition, results of operations or liquidity in any future periods.

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Pipeline Safety. The states in which we conduct operations administer federal pipeline safety standards under the Natural Gas Pipeline Safety Act of 1968, as amended, (the NGPSA), which requires certain pipelines to comply with safety standards in constructing and operating the pipelines and subjects the pipelines to regular inspections. Failure to comply with the NGPSA may result in the imposition of administrative, civil and criminal remedies. The rural gathering exemption under the NGPSA presently exempts substantial portions of our gathering facilities from jurisdiction under that statute. The portions of our facilities that are exempt include those portions located outside of cities, towns or any area designated as residential or commercial, such as a subdivision or shopping center. The rural gathering exemption, however, may be restricted in the future, and it does not apply to our intrastate natural gas pipelines.

Propane Segment

Products, Services and Marketing

We distribute propane through a nationwide retail distribution network consisting of 442 customer service locations in 41 states. Our operations are concentrated in large part in the western, upper midwestern, northeastern and southeastern regions of the United States. We serve more than one million active customers. Historically, approximately two-thirds of our retail propane volumes and substantially all of our propane-related operating income is attributable to sales during the six-month peak-heating season from October through March, as many customers use propane for heating purposes. Consequently, sales and operating profits are normally concentrated in the first and second fiscal quarters, while cash flows from operations are generally greatest during the second and third fiscal quarters when customers pay for propane purchased during the six-month peak season. To the extent necessary, we will reserve cash from peak periods for distribution to Unitholders during the warmer seasons.

Typically, customer service locations are found in suburban and rural areas where natural gas is not readily available. Generally, such locations consist of a one to two acre parcel of land, an office, a small warehouse and service facility, a dispenser and one or more 18,000 to 30,000 gallon storage tanks. Propane is generally transported from refineries, pipeline terminals, leased storage facilities and coastal terminals by rail or truck transports to our customer service locations where it is unloaded into storage tanks. In order to make a retail delivery of propane to a customer, a bobtail truck, which generally holds 2,500 to 3,000 gallons of propane, is loaded with propane from the storage tank. Propane is then delivered to the customer by the bobtail truck and pumped into a stationary storage tank on the customer s premises. We also deliver propane to retail customers in portable cylinders. We also deliver propane to certain other bulk end-users of propane in tractor-trailer transports, which typically have an average capacity of approximately 10,500 gallons. End-users receiving transport deliveries include industrial customers, large-scale heating accounts, mining operations and large agricultural accounts.

We encourage our customers whose propane needs are temperature sensitive to implement a regular delivery schedule. Many of our residential customers receive their propane supply pursuant to an automatic delivery system, which eliminates the customer s need to make an affirmative purchase decision and allows for more efficient route scheduling. We also sell, install and service equipment related to our propane distribution business, including heating and cooking appliances.

Approximately 96% of the domestic gallons we sold in the fiscal year ended August 31, 2006 were to retail customers and 4% were to wholesale customers. Of the retail gallons we sold, approximately 54% were to residential customers, 31% were to industrial, commercial and agricultural customers, and 15% were to other retail users. Sales to residential customers in the fiscal year ended August 31, 2006 accounted for 52% of total domestic gallons sold but accounted for approximately 66% of our gross profit from propane sales. Residential sales have a greater profit margin and a more stable customer base than the other markets we serve. Industrial, commercial and agricultural sales accounted for 25% of our gross profit from propane sales for the fiscal year ended August 31, 2006, with all other retail users accounting for 9%. Additional volumes sold to wholesale customers contributed 1% of our gross profit from propane sales. No single customer accounts for 10% or more of revenues.

The propane business is very seasonal with weather conditions significantly affecting demand for propane. We believe that the geographic diversity of our operations helps to reduce our overall exposure to less than favorable weather conditions in any particular region of the United States. Although overall demand for propane is affected by climate, changes in price and other factors, we believe our residential and commercial business to be relatively stable due to the following characteristics:

- residential and commercial demand for propane has been relatively unaffected by general economic conditions due to the largely non-discretionary nature of most propane purchases;

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- loss of customers to competing energy sources has been low due to the lack of availability or the high cost of alternative fuels;

- the tendency of our customers to remain with us due to the product being delivered pursuant to a regular delivery schedule and to our ownership as of August 31, 2006 of approximately 84% of the storage tanks utilized by our customers, which prevents fuel deliveries from competitors; and

- our historic ability to more than offset customer losses through internal growth of our customer base in existing markets.

Since home heating usage is the most sensitive to temperature, residential customers account for the greatest usage variation due to weather. Variations in the weather in one or more regions in which we operate can significantly affect the total volumes of propane that we sell and the margins realized thereon and, consequently, our results of operations. We believe that sales to the commercial and industrial markets, while affected by economic patterns, are not as sensitive to variations in weather conditions as sales to residential and agricultural markets.

Propane Supply and Storage

Our supplies of propane historically have been readily available from our supply sources. We purchase from over 50 energy companies and natural gas processors at numerous supply points located in the United States and Canada. In the fiscal year ended August 31, 2006, Enterprise Products Operating L.P. (Enterprise) and Targa Liquids (Targa) provided approximately 27.0% and 18.0% of our combined total propane supply, respectively. In addition, M-P Energy Partnership, a Canadian partnership in which our wholly-owned subsidiary, M.P. Oils, Ltd., owns a 60% interest, procured 22.0% of our combined total propane supply during the fiscal year ended August 31, 2006. M-P Energy Partnership buys and sells propane for its own account and supplies propane to us for our northern United States operations. Titan purchases substantially all of its propane from Enterprise pursuant to an agreement that expires in 2010.

We believe that if supplies from Enterprise or Targa were interrupted we would be able to secure adequate propane supplies from other sources without a material disruption of our operations. Aside from Enterprise, Targa, and the supply procured by M-P Energy Partnership, no single supplier provided more than 10% of our total domestic propane supply during the fiscal year ended August 31, 2006. We believe that our diversification of suppliers will enable us to purchase all of our supply needs at market prices without a material disruption of our operations if supplies are interrupted from any of our existing sources. Although we cannot assure you that supplies of propane will be readily available in the future, we expect a sufficient supply to continue to be available. However, increased demand for propane in periods of severe cold weather, or otherwise, could cause future propane supply interruptions or significant volatility in the price of propane.

Except for Titan s supply agreement, we typically enter into one-year supply agreements. The percentage of contract purchases may vary from year to year. Supply contracts generally provide for pricing in accordance with posted prices at the time of delivery or at the current prices established at major delivery or storage points, and some contracts include a pricing formula that typically is based on these market prices. Most of these agreements provide maximum and minimum seasonal purchase guidelines. We receive our supply of propane predominately through railroad tank cars and common carrier transport.

Because our profitability is sensitive to changes in wholesale propane costs, we generally seek to pass on increases in the cost of propane to customers. We have generally been successful in maintaining retail gross margins on an annual basis despite changes in the wholesale cost of propane, but there is no assurance that we will always be able to pass on product cost increases fully, particularly when product costs rise rapidly. Consequently, our profitability will be sensitive to changes in wholesale propane prices. See Management s Discussion and Analysis of Financial Condition and Results of Operations Overview.

We lease space in larger storage facilities in Michigan, Arizona, New Mexico and Texas, and smaller storage facilities in other locations, and have the opportunity to use storage facilities in additional locations when we pre-buy product from sources having such facilities. We believe that we have adequate third party storage to take advantage of supply purchasing advantages as they may occur from time to time. Access to storage facilities allows us to buy and store large quantities of propane during periods of low demand, which generally occur during the summer months, or at favorable prices, thereby helping to ensure a more secure supply of propane during periods of intense demand or price instability.

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Pricing Policy

Pricing policy is an essential element in the marketing of propane. We rely on regional management to set prices based on prevailing market conditions and product cost, as well as local management input. All regional managers are advised regularly of any changes in the posted price of each customer service location s propane suppliers. In most situations, we believe that our pricing methods will permit us to respond to changes in supply costs in a manner that protects our gross margins and customer base; to the extent such protection is possible. In some cases, however, our ability to respond quickly to cost increases could occasionally cause our retail prices to rise more rapidly than those of our competitors, possibly resulting in a loss of customers.

Billing and Collection Procedures

Customer billing and account collection responsibilities for our propane operations are retained at the local customer service locations. We believe that this decentralized approach is beneficial for several reasons:

- the customer is billed on a timely basis;
- the customer is more apt to pay a local business;
- cash payments are received more quickly; and
- local personnel have a current account status available to them at all times to answer customer inquiries.

Because propane sales to residential and commercial customers are affected by winter heating season requirements, our propane operations generally generate higher operating revenues and net income during the period from October through March of each year and lower operating revenues and, in some cases, lower net income or net losses during the period from April through September of each year. Sales to industrial and agricultural customers are much less weather-sensitive.

Gross profit margins are not only affected by weather patterns but also by changes in customer mix. For example, sales to residential customers generate higher margins than sales to other customer groups, such as commercial or agricultural customers. Wholesale margins are substantially lower than retail margins. In addition, gross profit margins vary by geographic region. Accordingly, a change in customer or geographic mix can affect gross profit without necessarily affecting total revenues.

Government Regulation and Environmental Matters

The operation of pipelines, plants and other facilities for gathering, compressing, treating, processing, or transporting natural gas, natural gas liquids and other products is subject to stringent and complex federal, state, and local laws and regulations governing the discharge of materials into the environment or otherwise relating to the protection of the environment. These laws and regulations can impair our business activities that affect the environment in many ways, such as:

- restricting the way we can release materials or waste products into the air, water, or soils;
- limiting or prohibiting construction activities in sensitive areas such as wetlands or areas of endangered species habitat, or otherwise constraining how or when construction is conducted;

- requiring remedial action to mitigate pollution from former operations, or requiring plans and activities to prevent pollution from ongoing operations; and

- imposing substantial liabilities on us for pollution resulting from our operations, including, for example, potentially enjoining the operations of facilities if it were determined that they were not in compliance with permit terms.

Costs of planning, designing, constructing and operating pipelines, plants and other facilities must incorporate compliance with environmental laws and regulations and safety standards. We have implemented environmental programs and policies designed to avoid potential liability and cost under applicable environmental laws and regulations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, the issuance of injunctions and the filing of federally authorized citizen suits.

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The clear trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus, any changes in environmental laws and regulations that result in more stringent and costly waste handling, storage, transport, disposal, or remediation requirements could have a material adverse effect on our operations and financial position. Moreover, risks of process upsets, accidental releases or spills are associated with our operations, and we cannot assure you that we will not incur significant costs and liabilities if such upsets, releases, or spills were to occur. In the event of future increases in costs, we may be unable to pass on those increases to our customers. While we believe that we are in substantial compliance with existing environmental laws and regulations and that continued compliance with current requirements would not have a material adverse effect on us, there is no assurance that this trend will continue in the future.

The Comprehensive Environmental Response, Compensation and Liability Act, as amended, also known as CERCLA or Superfund, and comparable state laws, impose liability without regard to fault or the legality of the original conduct on certain classes of persons who are considered to be responsible for the release of a hazardous substance into the environment, including those arising out of historical operations conducted by predecessors. Under CERCLA, these responsible persons may be subject to joint and several, strict 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, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances into the environment. Although petroleum is excluded from the definition of hazardous substance under CERCLA, we will generate materials in the course of our operations that may be regulated as hazardous substances. We also may incur liability under the Resource Conservation and Recovery Act, also known as RCRA, which imposes requirements related to the management and disposal of solid and hazardous wastes. While there exists an exclusion from the definition of hazardous wastes for drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy, in the course of our operations, we may generate unrecovered petroleum product wastes as well as ordinary industrial wastes such as paint wastes, waste solvents, and waste compressor oils that may be regulated as hazardous or solid wastes.

We currently own or lease, and have in the past owned or leased, numerous properties that for many years have been used for the measurement, gathering, field compression and processing of natural gas and NGLs. Although we used operating and disposal practices that were standard in the industry at the time, petroleum hydrocarbons or wastes may have been disposed of or released on or under the properties owned or leased by us, or on or under other locations where such wastes have been taken for disposal. In addition, some of these properties have been operated by third parties whose treatment and disposal or release of petroleum hydrocarbons and wastes was not under our control. These properties and the materials disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove or remediate previously disposed wastes or property contamination, or to perform remedial activities to prevent future contamination. A predecessor company acquired by us in July 2001 had previously received and responded to a request for information from the U.S. Environmental Protection Agency or EPA regarding its potential contribution to widespread groundwater contamination in San Bernardino, California, known as the Newmark Groundwater Contamination Superfund site. We have not received any follow-up correspondence from EPA on the matter since our acquisition of the predecessor company in 2001. In addition, through our acquisitions of ongoing businesses, we are currently involved in several remediation projects that have cleanup costs and related liabilities. As of August 31, 2006 an accrual of $1.4 million was recorded in our consolidated balance sheet to cover estimated environmental liabilities including certain matters assumed in connection with our acquisition of HPL. We have also recorded a receivable of $0.4 million to account for the predecessor owner s share of certain environmental liabilities of ETC OLP. In addition, we recorded an accrual of $3.0 million in connection with our acquisition of Titan for the potential environmental liabilities for three sites that were formerly owned by Titan or its predecessors.

The Federal Water Pollution Control Act of 1972, as amended, also known as the Clean Water Act, and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into state and federal waters. The discharge of pollutants into regulated waters is prohibited, except in accord with the terms of a permit issued by EPA or the state. Any unpermitted release of pollutants, including NGLs or condensates, from our systems or facilities could result in fines or penalties, as well as significant remedial obligations. We believe that we are in substantial compliance with the Clean Water Act. We currently expect to incur costs of approximately $0.1 million over the next year to upgrade or modify certain facilities as required under our spill prevention, control and countermeasures, or SPCC, plans.

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The Clean Air Act, as amended, and comparable state laws restrict the emission of air pollutants from many sources, including processing plants and compressor stations. These laws and any implementing regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions, impose stringent air permit requirements, or utilize specific equipment or technologies to control emissions. Failure to comply with these laws and regulations could expose us to civil and criminal enforcement actions. We received a state-issued Pipeline Facilities air emissions permit on June 30, 2005 for our Prairie Lea Compressor Station in Caldwell County, Texas, which historically has been designated as a grandfathered facility and, thus, was excluded from state air emissions permitting requirements. In order to comply with the terms of this permit and associated regulations requiring specified reductions in nitrogen oxides or NOx emissions by March 1, 2007, we are planning to modify the compressor engines at the facility during 2006, at an estimated cost of $2.0 million. In addition, we are currently pursuing agency-approved baseline monitoring of NOx emissions from our Katy Compressor Station in Harris County, Texas, which is in a non-attainment area for ozone. Once we develop this NOx baseline, we have been planning to purchase a sufficient amount of NOx emission allowances that would allow the facility to continue at its current level of operation in the non-attainment area, at an estimated cost of $2.3 million. These plans are subject to possible change however, as the non-attainment area is currently transitioning from a 1-hour ozone non-attainment area to an 8-hour ozone non-attainment area, which transition we expect will result in the adoption of further regulations that will perhaps change the extent to which NOx emissions reductions may be required.

Our operations are subject to regulation by the U.S. Department of Transportation or DOT under the Hazardous Liquid Pipeline Safety Act, or HLPSA, pursuant to which the DOT has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. HLPSA requires any entity which owns or operates pipeline facilities to permit access to and allow copying of records and to make certain reports and provide information as required by DOT. While we believe that our pipeline operations are in substantial compliance with applicable HLPSA requirements, there can be no assurance that future compliance with the HLPSA will not have a material adverse effect on our operations or financial position. Moreover, the DOT, through the Office of Pipeline Safety, has promulgated rules requiring pipeline operators to develop integrity management programs for gas transmission pipelines that, in the event of a failure, could impact high consequence areas, including areas with specified population densities. Activities under these integrity management programs involve the performance of internal pipeline inspections, pressure testing, or other effective means to assess the integrity of these regulated pipeline segments, and the regulations require prompt action to address integrity issues raised by the assessment and analysis. We estimate that compliance with these rules will result in capital costs of $21.3 million during the period between the remainder of calendar year 2006 to 2008 as well as operating and maintenance costs of $24.8 million during the three year period.

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

National Fire Protection Association Pamphlets No. 54 and No. 58, which establish rules and procedures governing the safe handling of propane, or comparable regulations, have been adopted as the industry standard in all of the states in which we operate. In some states these laws are administered by state agencies, and in others they are administered on a municipal level. With respect to the transportation of propane by truck, we are subject to regulations governing the transportation of hazardous materials under the Federal Motor Carrier Safety Act, administered by the DOT. We conduct ongoing training programs to help ensure that our operations are in compliance with applicable regulations. We believe that the procedures currently in effect at all of our facilities for the handling, storage, and distribution of propane are consistent with industry standards and are in substantial compliance with applicable laws and regulations.

Employees

As of October 13, 2006, we employ 604 people to operate our midstream and transportation and storage segments. We employ 3,898 full-time employees (including 8 which are considered partnership employees), of whom 70 are represented by labor unions, to operate our propane segments. We believe that our relations with our employees are satisfactory. Historically, our propane operations hire seasonal workers to meet peak winter demands.

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SEC Reporting

We electronically file certain documents with the SEC. We file annual reports on Form 10-K; quarterly reports on Form 10-Q; current reports on Form 8-K (as appropriate); along with any related amendments and supplements thereto. From time-to-time, we may also file registration and related statements pertaining to equity or debt offerings. You may read and copy any materials we file with the SEC at the SEC s Public Reference Room at 100 F Street, N.E., Washington, DC 20549. You may obtain information regarding the Public Reference Room by calling the SEC at 1-800-SEC-0330. In addition, the SEC maintains an Internet website at http://www.sec.gov that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC.

We provide electronic access to our periodic and current reports on our Internet website, www.energytransfer.com, free of charge. These reports are available on our website as soon as reasonably practicable after we electronically file such materials with the SEC.

ITEM 1A. RISK FACTORS

An investment in our securities involves a high degree of risk. You should carefully consider the following risk factors included below, together with all of the other information included in, or incorporated by reference into, this report in evaluating an investment in our securities. If any of these risks were to occur, our business, financial condition or results of operations could be adversely affected. In that case, the trading price of our Common Units could decline and you could lose all or part of your investment.

Risks Inherent in an Investment in Us

Cash distributions are not guaranteed and may fluctuate with our performance and other external factors.

The amount of cash we can distribute to holders of our Common Units or other partnership securities depends upon the amount of cash we generate from our operations. The amount of cash we generate from our operations will fluctuate from quarter to quarter and will depend upon, among other things:

- the amount of natural gas transported on the Oasis Pipeline and in our gathering systems;
- the level of throughput in our processing and treating operations;
- the fees we charge and the margins we realize for our services;
- the price of natural gas;
- the relationship between natural gas and NGL prices;
- the weather in our operating areas;
- the cost to us of the propane we buy for resale and the prices we receive for our propane;
- the level of competition from other propane companies and other energy providers;

- the level of our operating costs;
- prevailing economic conditions; and
- the level of our hedging activities.

In addition, the actual amount of cash available for distribution will also depend on other factors, such as:

- the level of capital expenditures we make;
- the cost of acquisitions, if any;
- the levels of any margin calls that result from changes in commodity prices;
- our debt service requirements;
- fluctuations in our working capital needs;

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our ability to make working capital borrowings under our credit facilities to make distributions;

restrictions on distributions contained in our debt agreements; and

the amount, if any, of cash reserves established by the General Partner in its discretion for the proper conduct of our business.

Because of all these factors, we cannot guarantee that we will have sufficient available cash to pay a specific level of cash distributions to our Unitholders.

Furthermore, you should be aware that the amount of cash we have available for distribution depends primarily upon our 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, we may make cash distributions during periods when we record net losses and may not make cash distributions during periods when we record net income.

We may sell additional limited partner interests, diluting existing interests of Unitholders.

Our partnership agreement allows us to issue an unlimited number of additional limited partner interests, including securities senior to the Common Units, without the approval of our Unitholders. The issuance of additional Common Units or other equity securities will have the following effects:

the current proportionate ownership interest of our Unitholders in us will decrease;

the amount of cash available for distribution on each Common Unit or partnership security may decrease;

the relative voting strength of each previously outstanding Common Unit may be diminished; and

the market price of the Common Units or partnership securities may decline.

Future sales of our units or other limited partner interests in the public market could reduce the market price of Unitholders limited partner interests.

As of August 31, 2006, ETE (formerly La Grange Energy, L.P.), owned 36,413,840 Common Units. ETE owns our General Partner. If ETE were to sell and/or distribute its Common Units to the holders of its equity interests in the future, those holders may dispose of some or all of these units. The sale or disposition of a substantial portion of these units in the public markets could reduce the market price of our outstanding Common Units.

Our increased debt level and debt agreements may limit our ability to make distributions to Unitholders and our future financial and operating flexibility.

As of August 31, 2006, we had approximately $2.6 billion of consolidated debt outstanding. Our level of indebtedness affects our operations in several ways, including, among other things:

a significant portion of our cash flow from operations will be dedicated to the payment of principal and interest on outstanding debt and will not be available for other purposes, including payment of distributions;

covenants contained in our existing debt arrangements require us to meet financial tests that may adversely affect our flexibility in planning for and reacting to changes in our business;

our ability to obtain additional financing for working capital, capital expenditures, acquisitions and general partnership purposes may be limited;

we may be at a competitive disadvantage relative to similar companies that have less debt;

we may be more vulnerable to adverse economic and industry conditions as a result of our significant debt level; and

failure to comply with the various restrictive and affirmative covenants of the credit agreements could negatively impact our ability and the ability of our subsidiaries to incur additional debt and our ability to pay our distributions. We are required to measure these financial tests and covenants quarterly and, as of August 31, 2006, we were in compliance with all financial requirements, tests, limitations, and covenants related to financial ratios under our existing credit agreements.

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Increases in interest rates could materially adversely affect our business, results of operations, cash flows and financial condition.

In addition to our exposure to commodity prices, we have significant exposure to increases in interest rates. As of August 31, 2006, we had approximately $2.6 billion of consolidated debt, of which approximately $1.4 billion was at fixed interest rates and approximately $1.2 billion was at variable interest rates, after giving effect to our existing interest swap arrangements. We manage a portion of our interest rate exposures by utilizing interest rate swaps and similar arrangements. To the extent that we have debt with variable interest rates that is not hedged, our results of operations, cash flows and financial condition, could be materially adversely affected by significant increases in interest rates.

An increase in interest rates may also cause a corresponding decline in demand for equity investments, in general, and in particular for yield-based equity investments such as our Common Units. Any such reduction in demand for our Common Units resulting from other more attractive investment opportunities may cause the trading price of our Common Units to decline.

The credit and risk profile of our General Partner and its owners could adversely affect our credit ratings and profile.

The credit and business risk profiles of our General Partner or owners of our General Partner may be factors in credit evaluations of us as a master limited partnership. This is because the General Partner can exercise significant influence over our business activities, including our cash distribution and acquisition strategy and business risk profile. Another factor that may be considered is the financial condition of our General Partner and its owners, including the degree of their financial leverage and their dependence on cash flow from the partnership to service their indebtedness.

Entities controlling the owner of our General Partner have significant indebtedness outstanding and are dependent principally on the cash distributions from their general and limited partner equity interests in us to service such indebtedness. Any distributions by us to such entities will be made only after satisfying our then current obligations to our creditors. Although we have taken certain steps in our organizational structure, financial reporting and contractual relationships to reflect the separateness of us, ETP GP and ETP LLC from the entities that control ETP GP, our credit ratings and business risk profile could be adversely affected if the ratings and risk profiles of such entities were viewed as substantially lower or more risky than ours.

The General Partner is not elected by the Unitholders and cannot be removed without its consent.

Unlike the holders of common stock in a corporation, Unitholders have only limited voting rights on matters affecting our business, and therefore limited ability to influence management s decisions regarding our business. Unitholders did not elect our General Partner and will have no right to elect our General Partner on an annual or other continuing basis. Although our General Partner has a fiduciary duty to manage us in a manner beneficial to Energy Transfer Partners, L.P. and the Unitholders, the directors of our General Partner and its General Partner, Energy Transfer Partners, L.L.C., have a fiduciary duty to manage the General Partner and its General Partner in a manner beneficial to the owners of those entities.

Furthermore, if the Unitholders are dissatisfied with the performance of our General Partner, they will have little ability to remove our General Partner. The General Partner generally may not be removed except upon the vote of the holders of 66 $^{2}/3$% of the outstanding units voting together as a single class, including units owned by the General Partner and its affiliates. As of August 31, 2006, ETE and its affiliates held approximately 33% of all the units, with an approximately 2% of units held by our officers and directors. Consequently, it could be difficult to remove the General Partner without the consent of the General Partner and our affiliates.

Furthermore, Unitholders voting rights are further restricted by the partnership agreement provision providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than the General Partner and its affiliates, cannot be voted on any matter.

The control of our General Partner may be transferred to a third party without Unitholder consent.

The General Partner may transfer its General Partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the Unitholders. Furthermore, there is no restriction in the partnership agreement on the ability of the general partner of our General Partner from transferring its general partner interest in our General Partner to a third party. Any new owner of the General Partner would be in a position to replace the officers of the General Partner with its own choices and to control the decisions taken by such officers.

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Unitholders may be required to sell their units to the General Partner at an undesirable time or price.

If at any time less than 20% of the outstanding units of any class are held by persons other than the General Partner and its affiliates, the General Partner will have the right to acquire all, but not less than all, of those units at a price no less than their then-current market price. As a consequence, a Unitholder may be required to sell his Common Units at an undesirable time or price. The General Partner may assign this purchase right to any of its affiliates or to us.

The interruption of distributions to us from our operating subsidiaries and equity investees may affect our ability to satisfy our obligations and to make distributions to our partners.

We are a holding company with no business operations. Our only significant assets are the equity interests we own in our operating subsidiaries and equity investees. As a result, we depend upon the earnings and cash flow of our operating subsidiaries and equity investees and the distribution of that cash to us in order to meet our obligations and to allow us to make distributions to our partners.

Cost reimbursements due to our General Partner may be substantial and may reduce our ability to pay the distributions to Unitholders.

Prior to making any distributions to our Unithholders, we will reimburse our General Partner for all expenses it has incurred on our behalf. In addition, our General Partner and its affiliates may provide us with services for which we will be charged reasonable fees as determined by the General Partner. The reimbursement of these expenses and the payment of these fees could adversely affect our ability to make distributions to the Unitholders. Our General Partner has sole discretion to determine the amount of these expenses and fees.

Unitholders may have liability to repay distributions.

Under certain circumstances Unitholders may have to repay us amounts wrongfully distributed to them. Under Delaware law, we may not make a distribution to you if the distribution causes our liabilities to exceed the fair value of our assets. Liabilities to partners on account of their partnership interests and non-recourse liabilities are not counted for purposes of determining whether a distribution is permitted. Delaware law provides that a limited partner who receives such a distribution and knew at the time of the distribution that the distribution violated Delaware law, will be liable to the limited partnership for the distribution amount for three years from the distribution date. Under Delaware law, an assignee who becomes a substituted limited partner of a limited partnership is liable for the obligations of the assignor to make contributions to the partnership. However, such an assignee is not obligated for liabilities unknown to him at the time he or she became a limited partner if the liabilities could not be determined from the partnership agreement.

Our partnership agreement limits our General Partner s fiduciary duties to our Unitholders and restricts the remedies available to Unitholders for actions taken by our General Partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that waive or consent to conduct by our General Partner and its affiliates and which reduce the obligations to which our General Partner would otherwise be held by state-law fiduciary duty standards. The following is a summary of the material restrictions contained in our partnership agreement on the fiduciary duties owed by our General Partner to the limited partners. Our partnership agreement:

- permits our General Partner to make a number of decisions in its sole discretion. This entitles our General Partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner;

- provides that our General Partner is entitled to make other decisions in its reasonable discretion ;

- generally provides that affiliated transactions and resolutions of conflicts of interest not involving a required vote of Unitholders must be fair and reasonable to us and that, in determining whether a transaction or resolution is fair and reasonable, our General Partner may consider the interests of all parties involved, including its own. Unless our General Partner has acted in bad faith, the action taken by our General Partner shall not constitute a breach of its fiduciary duty; and

provides that our General Partner and its officers and directors will not be liable for monetary damages to us, our limited partners or assignees for errors of judgment or for any acts or omissions if our General Partner and those other persons acted in good faith.

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In order to become a limited partner of our partnership, a common Unitholder is required to agree to be bound by the provisions in the partnership agreement, including the provisions discussed above.

Some of our executive officers and directors face potential conflicts of interest in managing our business.

Certain of our executive officers and directors are also officers and/or directors of ETE. These relationships may create conflicts of interest regarding corporate opportunities and other matters. The resolution of any such conflicts may not always be in our or our Unitholders best interests. In addition, these overlapping executive officers and directors allocate their time among us and ETE. These officers and directors face potential conflicts regarding the allocation of their time, which may adversely affect our business, results of operations and financial condition.

The General Partner s absolute discretion in determining the level of cash reserves may adversely affect our ability to make cash distributions to our Unitholders.

Our partnership agreement requires the General Partner to deduct from operating surplus cash reserves that in its reasonable discretion are necessary to fund our future operating expenditures. In addition, the partnership agreement permits the General Partner to reduce available cash by establishing cash reserves for the proper conduct of our business, to comply with applicable law or agreements to which we are a party or to provide funds for future distributions to partners. These cash reserves will affect the amount of cash available for distribution to Unitholders.

Our General Partner has conflicts of interest and limited fiduciary responsibilities, which may permit our General Partner to favor its own interests to the detriment of Unitholders.

As of August 31, 2006, ETE and its affiliates directly and indirectly owned an aggregate limited partner interest in us approximately 33% and our officers and directors owned approximately 2% of the limited partner interests in us. Conflicts of interest could arise in the future as a result of relationships between our General Partner and its affiliates, on the one hand, and us, on the other hand. As a result of these conflicts our General Partner may favor its own interests and those of its affiliates over the interests of the Unitholders. The nature of these conflicts includes the following considerations:

- Remedies available to Unitholders for actions that might, without the limitations, constitute breaches of fiduciary duty. Unitholders are deemed to have consented to some actions and conflicts of interest that might otherwise be deemed a breach of fiduciary or other duties under applicable state law.

- Our General Partner is allowed to take into account the interests of parties in addition to us in resolving conflicts of interest, thereby limiting its fiduciary duties to the Unitholders.

- Our General Partner s affiliates are not prohibited from engaging in other businesses or activities, including those in direct competition with us.

- Our General Partner determines the amount and timing of our asset purchases and sales, capital expenditures, borrowings and reserves, each of which can affect the amount of cash that is distributed to Unitholders.

- Our General Partner determines whether to issue additional units or other equity securities of us.

- Our General Partner determines which costs are reimbursable by us.

Our General Partner controls the enforcement of obligations owed to us by it.

Our General Partner decides whether to retain separate counsel, accountants or others to perform services for us.

Our General Partner is not restricted from causing us to pay it or its affiliates for any services rendered on terms that are fair and reasonable to us or entering into additional contractual arrangements with any of these entities on our behalf.

In some instances our General Partner may borrow funds in order to permit the payment of distributions, even if the purpose or effect of the borrowing is to make incentive distributions.

Risks Related to our Business

The profitability of our midstream, transportation and storage business is largely dependent upon natural gas commodity prices, price spreads between two or more physical locations and market demand for natural gas and NGLs, which are factors beyond our control and have been volatile.

Income from our midstream, transportation and storage business is exposed to risks due to fluctuations in commodity prices. For a portion of the natural gas gathered at the Southeast Texas System and at our Houston Pipeline System,

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we purchase natural gas from producers at the wellhead at a price that is at a discount to a specified index price and then gather and deliver the natural gas to pipelines where we typically resell the natural gas at the index price. Generally, the gross margins we realize under these discount-to-index arrangements decrease in periods of low natural gas prices because these gross margins are based on a percentage of the index price.

For a portion of the natural gas gathered at the Southeast Texas System, we enter into percentage-of-proceeds arrangements and keep-whole arrangements, pursuant to which we agree to gather and process natural gas received from the producers. Under percentage-of-proceeds arrangements, we generally sell the residue gas and NGLs at market prices and remit to the producers an agreed upon percentage of the proceeds based on an index price. In other cases, instead of remitting cash payments to the producer, we deliver an agreed upon percentage of the residue gas and NGL volumes to the producer and sell the volumes we keep to third parties at market prices. Under these arrangements our revenues and gross margins decline when natural gas prices and NGL prices decrease. Accordingly, a decrease in the price of natural gas or NGLs could have an adverse effect on our results of operations. Under keep-whole arrangements, we generally sell the NGLs produced from our gathering and processing operations to third parties at market prices. Because the extraction of the NGLs from the natural gas during processing reduces the Btu content of the natural gas, we must either purchase natural gas at market prices for return to producers or make a cash payment to producers equal to the value of this natural gas. Under these arrangements, our revenues and gross margins decrease when the price of natural gas increases relative to the price of NGLs if we are not able to bypass our processing plants and sell the unprocessed natural gas.

In the past, the prices of natural gas and NGLs have been extremely volatile, and we expect this volatility to continue. For example, during our fiscal year ended August 31, 2006, the NYMEX settlement price for the prompt month contract ranged from a high of $15.38 per MMBtu to a low of $5.52 per MMBtu. A composite of the Mt. Belvieu average NGLs price based upon our average NGLs composition during our fiscal year ended August 31, 2006 ranged from a high of approximately $1.18 per gallon to a low of approximately $0.87 per gallon.

Average realized natural gas sales prices for the twelve months ended August 31, 2006 exceeded our historical realized natural gas prices. For example, our average realized natural gas price increased $1.61, or 25%, from $6.43 per MMBtu for the year ended August 31, 2005 to $8.04 per MMBtu for the year ended August 31, 2006. On September 30, 2006, the NYMEX settlement price for October 2006 natural gas deliveries was $4.20 per MMBtu, which was 48% lower than our average natural gas price for the year ended August 31, 2006. Natural gas prices are subject to significant fluctuations, and we cannot assure you that natural gas prices will remain at the high levels recently experienced.

Our Oasis Pipeline, East Texas Pipeline System, ET Fuel System and Houston Pipeline System receive fees for transporting natural gas for our customers. Although a significant amount of the pipeline capacity of the East Texas Pipeline System and various pipeline segments of the ET Fuel System is committed under long-term fee-based contracts, the remaining capacity of our transportation pipelines is subject to fluctuation in demand based on the markets and prices for natural gas and NGLs, which factors may result in decisions by natural gas producers to reduce production of natural gas during periods of lower prices for natural gas and NGLs or may result in decisions by end users of natural gas and NGLs to reduce consumption of these fuels during periods of higher prices for these fuels. Our fuel retention fees are also directly impacted by changes in natural gas prices. Increases in natural gas prices tend to increase our fuel retention fees, and decreases in natural gas prices tend to decrease our fuel retention fees.

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

- the impact of weather on the demand for oil and natural gas;
- the level of domestic oil and natural gas production;
- the availability of imported oil and natural gas;
- actions taken by foreign oil and gas producing nations;

the availability of local, intrastate and interstate transportation systems;

the price, availability and marketing of competitive fuels;

the demand for electricity;

the impact of energy conservation efforts; and

the extent of governmental regulation and taxation.

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The use of derivative financial instruments could result in material financial losses by us.

From time to time, we have sought to limit a portion of the adverse effects resulting from changes in natural gas and other commodity prices and interest rates by using derivative financial instruments and other hedging mechanisms and by the activities we conduct in our trading operations. To the extent that we hedge our commodity price and interest rate exposures, we forego the benefits we would otherwise experience if commodity prices or interest rates were to change in our favor. In addition, even though monitored by management, our hedging and trading activities can result in losses. Such losses could occur under various circumstances, including if a counterparty does not perform its obligations under the hedge arrangement, the hedge is imperfect, or hedging policies and procedures are not followed.

Our success depends upon our ability to continually contract for new sources of natural gas supply.

In order to maintain or increase throughput levels on our gathering and transportation pipeline systems and asset utilization rates at our treating and processing plants, we must continually contract for new natural gas supplies and natural gas transportation services. We may not be able to obtain additional contracts for natural gas supplies for our natural gas gathering systems, and we may be unable to maintain or increase the levels of natural gas throughput on our transportation pipelines. The primary factors affecting our ability to connect new supplies of natural gas to our gathering systems include our success in contracting for existing natural gas supplies that are not committed to other systems and the level of drilling activity and production of natural gas near our gathering systems or in areas that provide access to our transportation pipelines or markets to which our systems connect. The primary factors affecting our ability to attract customers to our transportation pipelines consist of our access to other natural gas pipelines, natural gas markets, natural gas-fired power plants and other industrial end-users and the level of drilling and production of natural gas in areas connected to these pipelines and systems.

Fluctuations in energy prices can greatly affect production rates and investments by third parties in the development of new oil and natural gas reserves. Drilling activity and production generally decrease as oil and natural gas prices decrease. We have no control over the level of drilling activity in our areas of operation, the amount of reserves underlying the wells and the rate at which production from a well will decline, sometimes referred to as the decline rate. In addition, we have no control over producers or their production decisions, which are affected by, among other things, prevailing and projected energy prices, demand for hydrocarbons, the level of reserves, geological considerations, governmental regulation and the availability and cost of capital.

A substantial portion of our assets, including our gathering systems and our processing and treating plants, are connected to natural gas reserves and wells for which the production will naturally decline over time. In particular, the Southeast Texas System covers portions of the Austin Chalk, Buda, Georgetown, Edwards, Wilcox and other producing formations in southeast Texas, which we collectively refer to as the Austin Chalk trend. This natural gas producing region has generally been characterized by high initial flow rates followed by steep initial declines in production. Accordingly, our cash flows will also decline unless we are able to access new supplies of natural gas by connecting additional production to these systems.

Our transportation pipelines are also dependent upon natural gas production in areas served by our pipelines or in areas served by other gathering systems or transportation pipelines that connect with our transportation pipelines. A material decrease in natural gas production in our areas of operation or in other areas that are connected to our areas of operation by third party gathering systems or pipelines, as a result of depressed commodity prices or otherwise, would result in a decline in the volume of natural gas we handle, which would reduce our revenues and operating income. In addition, our future growth will depend, in part, upon whether we can contract for additional supplies at a greater rate than the rate of natural decline in our currently connected supplies.

The volumes of natural gas we transport on our pipelines may be reduced in the event that the prices at which natural gas is purchased and sold at the Waha Hub, the Katy Hub, the Carthage Hub and the Houston Ship Channel Hub, the four major natural gas trading hubs served by our pipelines, become unfavorable in relation to prices for natural gas at other natural gas trading hubs or in other markets as customers may elect to transport their natural gas to these other hubs or markets using pipelines other than those we operate.

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We may not be able to fully execute our growth strategy if we encounter illiquid capital markets or increased competition for qualified assets.

Our strategy contemplates growth through the development and acquisition of a wide range of midstream, transportation, storage, propane and other energy infrastructure assets while maintaining a strong balance sheet. This strategy includes constructing and acquiring additional assets and businesses to enhance our ability to compete effectively and diversify our asset portfolio, thereby providing more stable cash flow. We regularly consider and enter into discussions regarding, and are currently contemplating, the acquisition of additional assets and businesses, stand alone development projects or other transactions that we believe will present opportunities to realize synergies and increase our cash flow.

Consistent with our acquisition strategy, we are continuously engaged in discussions with potential sellers regarding the possible acquisition of additional assets or businesses. Such acquisition efforts may involve our participation in processes that involve a number of potential buyers, commonly referred to as auction processes, as well as situations in which we believe we are the only party or one of a very limited number of potential buyers in negotiations with the potential seller. We cannot assure you that our current or future acquisition efforts will be successful or that any such acquisition will be completed on terms considered favorable to us.

In addition, we are experiencing increased competition for the assets we purchase or contemplate purchasing. Increased competition for a limited pool of assets could result in us losing to other bidders more often or acquiring assets at higher prices. Either occurrence would limit our ability to fully execute our growth strategy. Inability to execute our growth strategy may materially adversely impact the market price of our securities.

An impairment of goodwill and intangible assets could reduce our earnings.

At August 31, 2006, our consolidated balance sheet reflected $604.4 million of goodwill and $182.4 million of intangible assets. Goodwill is recorded when the purchase price of a business exceeds the fair market value of the tangible and separately measurable intangible net assets. Accounting principles generally accepted in the United States require us to test goodwill for impairment on an annual basis or when events or circumstances occur indicating that goodwill might be impaired. Long-lived assets such as intangible assets with finite useful lives are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. If we determine that any of our goodwill or intangible assets were impaired, we would be required to take an immediate charge to earnings with a correlative effect on partners equity and balance sheet leverage as measured by debt to total capitalization.

If we do not make acquisitions on economically acceptable terms, our future growth could be limited.

Historically, our results of operations and our ability to grow and to increase distributions to Unitholders has depended principally on our ability to make acquisitions that are accretive to our distributable cash flow per unit. Our acquisition strategy is based, in part, on our expectation of ongoing divestitures of pipeline assets by large industry participants. A material decrease in such divestitures would limit our opportunities for future acquisitions and could adversely affect our business, results of operations, financial condition and cash flows available for distribution to our Unitholders.

In addition, we may be unable to make accretive acquisitions for any of the following reasons, among others:

- because we are unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them;
- because we are unable to raise financing for such acquisitions on economically acceptable terms; or
- because we are outbid by competitors, some of which are substantially larger than us and have greater financial resources and lower costs of capital then we do.

Furthermore, even if we consummate acquisitions that we believe will be accretive, those acquisitions may in fact adversely affect our results of operations or result in no increase or even a decrease in distributable cash flow per unit. Any acquisition involves potential risks, including the risk that we may:

fail to realize anticipated benefits, such as new customer relationships, cost-savings or cash flow enhancements;

decrease our liquidity by using a significant portion of our available cash or borrowing capacity to finance acquisitions;

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- significantly increase our interest expense or financial leverage if we incur additional debt to finance acquisitions;
- encounter difficulties operating in new geographic areas or new lines of business;
- incur or assume unanticipated liabilities, losses or costs associated with the business or assets acquired for which we are not indemnified or for which the indemnity is inadequate;
- be unable to hire, train or retrain qualified personnel to manage and operate our growing business and assets;
- less effectively manage our historical assets, due to the diversion of management s attention from other business concerns; or
- incur other significant charges, such as impairment of goodwill or other intangible assets, asset devaluation or restructuring charges.

If we consummate future acquisitions, our capitalization and results of operations may change significantly. As we determine the application of our funds and other resources, you will not have an opportunity to evaluate the economics, financial and other relevant information that we will consider.

Our actual construction, development and acquisition costs could exceed forecasted amounts.

We may have significant expenditures for the development and construction of energy infrastructure assets, including some construction and development projects with significant technological challenges. We may not be able to complete our projects at the costs estimated at the time of each project s initiation.

We depend on certain key producers for our supply of natural gas on the Southeast Texas System, and the loss of any of these key producers could adversely affect our financial results.

As of August 31, 2006, Anadarko Petroleum Corp. and Chesapeake Energy Corp. supplied us with approximately 44% of the Southeast Texas System s natural gas supply. We are not the only option available to these producers for disposition of the natural gas they produce. To the extent that these and other producers may reduce the volumes of natural gas that they supply us, we would be adversely affected unless we were able to acquire comparable supplies of natural gas from other producers.

We depend on key customers to transport natural gas on our East Texas Pipeline System and ET Fuel System.

We have entered into nine- and ten-year fee-based transportation contracts with XTO Energy, Inc. pursuant to which XTO Energy has committed to transport certain minimum volumes of natural gas on our pipelines. We have also entered into an eight-year fee-based transportation contract with TXU Portfolio Management Company, L.P., a subsidiary of TXU Corp., which we refer to as TXU Shipper, to transport natural gas on the ET Fuel System to TXU s electric generating power plants. We have also entered into two eight-year natural gas storage contracts with TXU Shipper to store natural gas at the two natural gas storage facilities that are part of the ET Fuel System. Each of the contracts with TXU Shipper may be extended by TXU Shipper for two additional five-year terms. The failure of XTO Energy or TXU Shipper to fulfill their contractual obligations under these contracts could have a material adverse effect on our cash flow and results of operations if we were not able to replace these customers under arrangements that provide similar economic benefits as these existing contracts.

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

As a natural gas gatherer and intrastate pipeline company, we are generally exempt from Federal Energy Regulatory Commission, or FERC, regulation under the Natural Gas Act of 1938, or NGA, but FERC regulation still significantly affects our business and the market for our products. In recent years, FERC has pursued pro-competitive policies in the regulation of interstate natural gas pipelines. However, we cannot assure you that FERC will continue this approach as it considers matters such as pipeline rates and rules and policies that may affect rights of access to natural gas transportation capacity, transportation and storage facilities. The rates, terms and conditions of some of the transportation and storage services we provide on the Oasis Pipeline and the ET Fuel System are subject to FERC regulation under Section 311 of the Natural Gas Policy Act, or NGPA. Under Section 311, rates charged for transportation and storage must be fair and equitable amounts. Amounts collected in excess of fair and equitable rates are subject to refund with interest, and the terms and conditions of service, set forth in the pipeline s Statement of Operating Conditions, are subject to FERC approval. Failure to observe the service limitations

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applicable to storage and transportation service under Section 311, failure to comply with the rates approved by FERC for Section 311 service, and failure to comply with the terms and conditions of service established in the pipeline s FERC-approved Statement of Operating Conditions could result in an alteration of jurisdictional status and/or the imposition of administrative, civil and criminal penalties.

Our intrastate natural gas transportation and storage facilities are subject to state regulation in Texas and Louisiana, the states in which we operate these types of pipelines. Our intrastate transportation facilities located in Texas are subject to regulation as common purchasers and as gas utilities by the Texas Railroad Commission, or TRRC. The TRRC s jurisdiction extends to both rates and pipeline safety. The rates we charge for transportation and storage services are deemed just and reasonable under Texas law unless challenged in a complaint. Should a complaint be filed or should regulation become more active, our business may be adversely affected.

Our pipeline operations are also subject to ratable take and common purchaser statutes in Texas and Louisiana, the states where we operate. Ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes have the effect of restricting our right as an owner of gathering facilities to decide with whom we contract to purchase or transport natural gas. Federal law leaves any economic regulation of natural gas gathering to the states, and some of the states in which we operate have adopted complaint-based or other limited economic regulation of natural gas gathering activities. States in which we operate that have adopted some form of complaint-based regulation, like 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 rates and access. Other state and local regulations also affect our business.

Our storage facilities are also subject to the jurisdiction of the TRRC. Generally, the TRRC has jurisdiction over all underground storage of natural gas in Texas, unless the facility is part of an interstate gas pipeline facility. Because the ET Fuel System and the Houston Pipeline System natural gas storage facilities are only connected to intrastate gas pipelines, they fall within the TRRC s jurisdiction and must be operated pursuant to TRRC permit. Certain changes in ownership or operation of TRCC jurisdictional storage facilities, such as facility expansions and increases in the maximum operating pressure, must be approved by the TRRC through an amendment to the facility s existing permit. In addition, the TRRC must approve transfers of the permits. The TRRC s regulations also require all natural gas storage facilities to be operated to prevent waste, the uncontrolled escape of gas, pollution and danger to life or property. Accordingly, the TRRC requires natural gas storage facilities to implement certain safety, monitoring, reporting and record-keeping measures. Violations of the terms and provisions of a TRRC permit or a TRRC order or regulation can result in the modification, cancellation or suspension of an operating permit and/or civil penalties, injunctive relief, or both.

The states in which we conduct operations administer federal pipeline safety standards under the Pipeline Safety Act of 1968, which requires certain pipeline companies to comply with safety standards in constructing and operating the pipelines, and subjects pipelines to regular inspections. Some of our gathering facilities are exempt from the requirements of this Act. In respect to recent pipeline accidents in other parts of the country, Congress and the Department of Transportation have passed or are considering heightened pipeline safety requirements.

Failure to comply with applicable regulations under the NGA, NGPA, Pipeline Safety Act and certain state laws could result in the imposition of administrative, civil and criminal remedies.

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

Our natural gas midstream, transportation and storage, as well as our propane, businesses are subject to stringent federal, state, and local environmental laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may require the acquisition of permits for our operations, result in capital expenditures to manage, limit, or prevent emissions, discharges, or releases of various materials from our pipelines, plants, and facilities, and impose substantial liabilities for pollution resulting from our operations. Several governmental authorities, such as the U.S. Environmental Protection Agency, have the power to enforce compliance with these laws and regulations and the permits issued under them and frequently mandate difficult and costly remediation measures and other actions. Failure to comply with these laws, regulations, and permits may result in the assessment of administrative, civil, and criminal penalties, the imposition of remedial obligations, and the issuance of injunctive relief.

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We may incur substantial environmental costs and liabilities because the underlying risk are inherent to our operations. Joint and several, strict liability may be incurred under environmental laws and regulations in connection with discharges or releases of petroleum hydrocarbons or wastes on, under, or from our properties and facilities, many of which have been used for industrial activities for a number of years. Private parties, including the owners of properties through which our gathering systems pass or facilities where our petroleum hydrocarbons or wastes are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage. In addition, changes in environmental laws and regulations occur frequently, and any such changes that result in more stringent and costly waste handling, storage, transport disposal or remediation requirements could have a material adverse effect on our operations or financial position.

Any reduction in the capacity of, or the allocations to, our shippers in interconnecting, third-party pipelines could cause a reduction of volumes transported in our pipelines, which would adversely affect our revenues and cash flow.

Users of our pipelines are dependent upon connections to and from third-party pipelines to receive and deliver natural gas and NGLs. Any reduction in the capacities of these interconnecting pipelines due to testing, line repair, reduced operating pressures, or other causes could result in reduced volumes being transported in our pipelines. Similarly, if additional shippers begin transporting volumes of natural gas and NGLs over interconnecting pipelines, the allocations to existing shippers in these pipelines would be reduced, which could also reduce volumes transported in our pipelines. Any reduction in volumes transported in our pipelines would adversely affect our revenues and cash flow.

We encounter competition from other midstream, transportation and storage companies and propane companies.

We experience competition in all of our markets. Our principal areas of competition include obtaining natural gas supplies for the Southeast Texas System and natural gas transportation customers for the Oasis Pipeline, the East Texas Pipeline System and the ET Fuel System. Our competitors include major integrated oil companies, interstate and intrastate pipelines and companies that gather, compress, treat, process, transport, store and market natural gas. The Southeast Texas System competes with natural gas gathering and processing systems owned by Duke Energy Field Services, LLC. The East Texas Pipeline competes with other natural gas transportation pipelines that serve the Bossier Sands area in east Texas and the Barnett Shale area of the Fort Worth Basin in north Texas. The ET Fuel System competes with a number of other natural gas pipelines, including interstate and intrastate pipelines that link the Waha Hub, and the Fort Worth Basin Pipeline competes with other natural gas transportation pipelines serving the Dallas/Ft. Worth area and other pipelines that serve the east central Texas and south Texas markets. Pipelines that we compete with in these areas include those owned by Atmos Energy Corporation, Enterprise Products Partners, L.P., and Enbridge, Inc. Some of our competitors may have greater financial resources and access to larger natural gas supplies than we do.

The acquisition of the Houston Pipeline System increased the number of interstate pipelines and natural gas markets to which we have access and expanded our principal areas of competition to areas such as southeast Texas and the Texas Gulf Coast. As a result of our expanded market presence and diversification, we face additional competitors, such as major integrated oil companies, interstate and intrastate pipelines and companies that gather, compress, treat, process, transport, store and market natural gas, that may have greater financial resources and access to larger natural gas supplies than we do.

Our propane business competes with a number of large national and regional propane companies and several thousand small independent propane companies. Because of the relatively low barriers to entry into the retail propane market, there is potential for small independent propane retailers, as well as other companies that may not currently be engaged in retail propane distribution, to compete with our retail outlets. As a result, we are always subject to the risk of additional competition in the future. Generally, warmer-than-normal weather further intensifies competition. Most of our propane retail branch locations compete with several other marketers or distributors in their service areas. The principal factors influencing competition with other retail propane marketers are:

- price,
- reliability and quality of service,
- responsiveness to customer needs,

safety concerns,

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- long-standing customer relationships,
- the inconvenience of switching tanks and suppliers, and
- the lack of growth in the industry.

Expanding our business by constructing new pipelines and treating and processing facilities subjects us to risks.

One of the ways that we expect to grow our business is through the construction of additions to our existing gathering, compression, treating, processing and transportation systems. The construction of a new pipeline or the expansion of an existing pipeline, by adding additional compression capabilities or by adding a second pipeline along an existing pipeline, and the construction of new processing or treating facilities, involve numerous regulatory, environmental, political and legal uncertainties beyond our control and require the expenditure of significant amounts of capital that we will be required to finance through borrowings, the issuance of additional equity or from operating cash flow. If we undertake these projects, they may not be completed on schedule or at all or at the budgeted cost. Moreover, our revenues may not increase immediately following the completion of particular projects. For instance, if we build a new pipeline, the construction will occur over an extended period of time, but we may not materially increase our revenues until long after the project s completion. Moreover, we may construct facilities to capture anticipated future growth in production in a region in which such growth does not materialize. As a result, new facilities may be unable to attract enough throughput to achieve our expected investment return, which could adversely affect our results of operations and financial condition. As a result, the success of a pipeline construction project will likely depend upon the level of natural gas exploration and development drilling activity in the areas proposed to be serviced by the project as well as our ability to obtain commitments from producers in this area to utilize the newly constructed pipelines.

We are exposed to the credit risk of our customers, and an increase in the nonpayment and nonperformance by our customers could reduce our ability to make distributions to our Unitholders.

The risks of nonpayment and nonperformance by our customers are a major concern in our business. Participants in the energy industry have been subjected to heightened scrutiny from the financial markets in light of past collapses and failures of other energy companies. We are subject to risks of loss resulting from nonpayment or nonperformance by our customers. Any substantial increase in the nonpayment and nonperformance by our customers could reduce our ability to make distributions to our Unitholders.

We may be unable to bypass the La Grange processing plant, which could expose us to the risk of unfavorable processing margins.

Because of our ownership of the Oasis Pipeline, we can generally elect to bypass the La Grange processing plant when processing margins are unfavorable and instead deliver pipeline-quality gas by blending rich gas from the Southeast Texas System with lean gas transported on the Oasis Pipeline. In some circumstances, such as when we do not have a sufficient amount of lean gas to blend with the volume of rich gas that we receive at the La Grange processing plant, we may have to process the rich gas. If we have to process when processing margins are unfavorable, our results of operations will be adversely affected.

We may be unable to retain existing customers or secure new customers, which would reduce our revenues and limit our future profitability.

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

For our fiscal year ended August 31, 2006, approximately 40% of our sales of natural gas 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 increasingly 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 many companies of greatly varying size and financial capacity that compete with us in the marketing of natural gas, we often compete in the end-user and utilities markets primarily on the basis of price. The inability of our management to renew or replace our current contracts as they expire and to respond appropriately to changing market conditions could have a negative effect on our profitability.

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Our storage business depends on neighboring pipelines to transport natural gas.

To obtain natural gas, our storage business depends on the pipelines to which they have access. Many of these pipelines are owned by parties not affiliated with us. Any interruption of service on those pipelines or adverse change in their terms and conditions of service could have a material adverse effect on our ability, and the ability of our customers, to transport natural gas to and from our facilities and a corresponding material adverse effect on our storage revenues. In addition, the rates charged by those interconnected pipelines for transportation to and from our facilities affect the utilization and value of our storage services. Significant changes in the rates charged by those pipelines or the rates charged by other pipelines with which the interconnected pipelines compete could also have a material adverse effect on our storage revenues.

Our pipeline integrity program may cause us to incur significant costs and liabilities.

In December 2003, the U.S. Department of Transportation issued a final rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the rule refers to as high consequence areas. The final rule resulted from the enactment of the Pipeline Safety Improvement Act of 2002. The final rule was effective as of January 14, 2004. Based on the results of our current pipeline integrity testing programs, we estimate that compliance with this final rule for our existing transportation assets will result in capital costs of $21.3 million during the period between 2006 to 2008, as well as operating and maintenance costs of $24.8 million during that three-year period. Integrity testing and assessment of all of these assets will continue, and the potential exists that results of such testing and assessment could cause us to incur even greater capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines.

Since weather conditions may adversely affect demand for propane, our financial conditions may be vulnerable to warm winters.

Weather conditions have a significant impact on the demand for propane for heating purposes because the majority of our customers rely heavily on propane as a heating fuel. Typically, we sell approximately two-thirds of our retail propane volume during the peak-heating season of October through March. Our results of operations can be adversely affected by warmer winter weather which results in lower sales volumes. In addition, to the extent that warm weather or other factors adversely affect our operating and financial results, our access to capital and our acquisition activities may be limited. Variations in weather in one or more of the regions where we operate can significantly affect the total volume of propane that we sell and the profits realized on these sales. Agricultural demand for propane may also be affected by weather, including periods of unseasonably cold or hot periods or dry weather conditions which may impact agricultural operations.

A natural disaster, catastrophe or other event could result in severe personal injury, property damage and environmental damage, which could curtail our operations and otherwise materially adversely affect our cash flow and, accordingly, affect the market price of our Common Units.

Some of our operations involve risks of personal injury, property damage and environmental damage, which could curtail our operations and otherwise materially adversely affect our cash flow. For example, natural gas facilities operate at high pressures, sometimes in excess of 1,100 pounds per square inch. Virtually all of our operations are exposed to potential natural disasters, including hurricanes, tornadoes, storms, floods and/or earthquakes.

If one or more facilities that are owned by us or that deliver natural gas or other products to us are damaged by severe weather or any other disaster, accident, catastrophe or event, our operations could be significantly interrupted. Similar interruptions could result from damage to production or other facilities that supply our facilities or other stoppages arising from factors beyond our control. These interruptions might involve significant damage to people, property or the environment, and repairs might take from a week or less for a minor incident to six months or more for a major interruption. Any event that interrupts the revenues generated by our operations, or which causes us to make significant expenditures not covered by insurance, could reduce our cash available for paying distributions and, accordingly, adversely affect the market price of our Common Units.

We believe that we maintain adequate insurance coverage, although insurance will not cover many types of interruptions that might occur. As a result of market conditions, premiums and deductibles for certain insurance policies can increase substantially, and in some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. As a result, we may not be able to renew existing insurance policies or procure other desirable insurance on commercially reasonable terms, if at all. If we were to incur a significant

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liability for which we were not fully insured, it could have a material adverse effect on our financial position and results of operations. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient if such an event were to occur.

Terrorist attacks aimed at our facilities could adversely affect our business, results of operations, cash flows and financial condition.

Since the September 11, 2001 terrorist attacks on the United States, the United States government has issued warnings that energy assets, including our nation s pipeline infrastructure, may be the future target of terrorist organizations. Any terrorist attack on our facilities or pipelines or those of our customers could have a material adverse effect on our business.

Sudden and sharp propane price increases that cannot be passed on to customers may adversely affect our profit margins.

The propane industry is a margin-based business in which gross profits depend on the excess of sales prices over supply costs. As a result, our profitability is sensitive to changes in energy prices, and in particular, changes in wholesale prices of propane. When there are sudden and sharp increases in the wholesale cost of propane, we may be unable to pass on these increases to our customers through retail or wholesale prices. Propane is a commodity and the price we pay for it can fluctuate significantly in response to changes in supply or other market conditions over which we have no control. In addition, the timing of cost pass-throughs can significantly affect margins. Sudden and extended wholesale price increases could reduce our gross profits and could, if continued over an extended period of time, reduce demand by encouraging our retail customers to conserve their propane usage or convert to alternative energy sources.

Our results of operations and our ability to make distributions or pay interest or principal on debt securities could be negatively impacted by price and inventory risk related to our propane business and management of these risks.

We generally attempt to minimize our cost and inventory risk related to our propane business by purchasing propane on a short-term basis under supply contracts that typically have a one-year term and at a cost that fluctuates based on the prevailing market prices at major delivery points. In order to help ensure adequate supply sources are available during periods of high demand, we may purchase large volumes of propane during periods of low demand or low price, which generally occur during the summer months, for storage in our facilities, at major storage facilities owned by third parties or for future delivery. This strategy may not be effective in limiting our cost and inventory risks if, for example, market, weather or other conditions prevent or allocate the delivery of physical product during periods of peak demand. If the market price falls below the cost at which we made such purchases, it could adversely affect our profits.

Some of our propane sales are pursuant to commitments at fixed prices. To mitigate the price risk related to our anticipated sales volumes under the commitments, we may purchase and store physical product and/or enter into fixed price over-the-counter energy commodity forward contracts and options. Generally, over-the-counter energy commodity forward contracts have terms of less than one year. We enter into such contracts and exercise such options at volume levels that we believe are necessary to manage these commitments. The risk management of our inventory and contracts for the future purchase of product could impair our profitability if the customers do not fulfill their obligations.

We also engage in other trading activities, and may enter into other types of over-the-counter energy commodity forward contracts and options. These trading activities are based on our management s estimates of future events and prices and are intended to generate a profit. However, if those estimates are incorrect or other market events outside of our control occur, such activities could generate a loss in future periods and potentially impair our profitability.

We are dependent on our principal propane suppliers, which increases the risk of an interruption in supply.

During fiscal 2006, we purchased approximately 27% of our propane from Enterprise Products Operating L.P., approximately18% from Targa Liquids, and approximately 22% of our propane from M-P Energy Partnership, the Canadian partnership in which we own a 60% interest. Titan purchases substantially all of its propane from Enterprise pursuant to an agreement that expires in 2010. If supplies from these sources were interrupted, the cost of procuring replacement supplies and transporting those supplies from alternative locations might be materially higher

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and, at least on a short-term basis, margins could be adversely affected. Supply from Canada is subject to the additional risk of disruption associated with foreign trade such as trade restrictions, shipping delays and political, regulatory and economic instability.

Historically, a substantial portion of the propane that we purchase has originated from one of the industry s major markets located in Mt. Belvieu, Texas and has been shipped to us through major common carrier pipelines. Any significant interruption in the service at Mt. Belvieu or other major market points, or on the common carrier pipelines we use, would adversely affect our ability to obtain propane.

Competition from alternative energy sources may cause us to lose propane customers, thereby reducing our revenues.

Competition in our propane business from alternative energy sources has been increasing as a result of reduced regulation of many utilities. Propane is generally not competitive with natural gas in areas where natural gas pipelines already exist because natural gas is a less expensive source of energy than propane. The gradual expansion of natural gas distribution systems and the availability of natural gas in many areas that previously depended upon propane could cause us to lose customers, thereby reducing our revenues. Fuel oil also competes with propane and is generally less expensive than propane. In addition, the successful development and increasing usage of alternative energy sources could adversely affect our operations.

Energy efficiency and technological advances may affect the demand for propane and adversely affect our operating results.

The national trend toward increased conservation and technological advances, including installation of improved insulation and the development of more efficient furnaces and other heating devices, has decreased the demand for propane by retail customers. Stricter conservation measures in the future or technological advances in heating, conservation, energy generation or other devices could adversely affect our operations.

Tax Risks to Common Unitholders

The IRS could treat us as a corporation for tax purposes, which would substantially reduce the cash available for distribution to Unitholders.

The anticipated after-tax economic benefit of an investment in our Common Units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this or any other matter affecting us.

Despite the fact that we are a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. Although we do not believe based upon our current operations that we are so treated, a change in our business (or a change in current law) could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation personally as an entity.

If we were so treated as a corporation, we would pay federal income tax on our income at the corporate tax rate, which is currently a maximum of 35% and we would likely pay additional state income taxes as well. Distributions to Unitholders would generally be taxed again as corporate distributions, and none of our income, gains, losses or deductions would flow through to Unitholders. Because an additional, material tax would be imposed upon us in that case, our cash available for distribution to Unitholders would be substantially reduced. Therefore, our treatment as a corporation would result in a material reduction in the available cash distributions to the Unitholders, likely causing a substantial reduction in the value of our Common Units.

In addition, various states may evaluate ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other forms of taxation. If any state were to impose a tax upon us personally as an entity, the cash available for distribution to you would be reduced. Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that causes us to be treated as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, then the minimum quarterly distribution and the target distribution levels will be adjusted to reflect that impact on us.

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A successful IRS contest of the federal income tax positions we take may adversely affect the market for Common Units and the costs of any contest will be borne by our Unitholders and our General Partner.

We have not requested a ruling from the IRS with respect to any matter affecting us. The IRS may adopt positions that differ from the conclusions of our counsel or from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain our counsel s conclusions or the positions we take. A court may not concur with some or all of our counsel s conclusions or the positions we take. Any contest with the IRS may materially and adversely affect the market for our Common Units and the price at which they trade. In addition, the costs of any contest with the IRS, principally legal, accounting and related fees, will be indirectly borne by our Unitholders and our General Partner since such costs will reduce the amount of cash available for distribution.

Unitholders may be required to pay taxes on their share of our income even if they do not receive any cash distributions from us.

Unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from the taxation of their share of our taxable income. In such case, Unitholders would still be required to pay federal income taxes and, in some cases, state and local income taxes on their share of our taxable income regardless of the amount, if any, of any cash distributions they receive from us.

Only calendar year taxpayers may become partners.

Only calendar year taxpayers may purchase Common Units. Any Unitholder who is not a calendar year taxpayer will not be admitted to Energy Transfer Partners, L.P. as a partner, will not be entitled to receive distributions or federal income tax allocations from Energy Transfer Partners, L.P. and may only transfer these Common Units to a purchaser or other transferee.

Tax gain or loss on disposition of Common Units could be different than expected.

Unitholders who sell Common Units will recognize gain or loss equal to the difference between the amount realized and their tax basis in those Common Units. Prior distributions in excess of the total net taxable income allocated for a Common Unit that decreased a Unitholder s tax basis in that Common Unit will, in effect, become taxable income to the Unitholder if the Common Unit is sold at a price greater than the Unitholder s tax basis in that Common Unit, even if the price is less than his original cost. A substantial portion of the amount the Unitholder realizes, whether or not representing gain, will likely be ordinary income to the Unitholder. Should the IRS successfully contest some positions we take, a Unitholder could recognize more gain on the sale of Common Units than would be the case under those positions, without the benefit of decreased income in prior years. Also, Unitholders who sell Common Units may incur a tax liability in excess of the amount of cash they receive from the sale.

Tax-exempt entities and foreign persons face unique tax issues from owning Common Units that may result in adverse tax consequences to them.

Investment in Common Units by tax-exempt entities, including employee benefit plans and individual retirement accounts (known as IRAs) and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to Unitholders who are organizations exempt from federal income tax, may be taxable to them as unrelated business taxable income . Distributions to non-U.S. persons will be reduced by withholding taxes, at the highest applicable rate, and non-U.S. persons will be required to file federal income tax returns and generally pay tax on their share of our taxable income. If you are a tax-exempt entity or a non-U.S. person, you should consult your tax advisor before investing in our Common Units.

We will treat each purchaser of Common Units as having the same tax benefits without regard to the units purchased. The IRS may challenge this treatment, which could adversely affect the value of the units.

Because we cannot match transferors and transferees of Common Units, we will adopt depreciation and amortization positions that do not conform with all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to you. It also could affect the timing of these tax benefits or the amount of gain from the Unitholder s sale of Common Units and could have a negative impact on the value of the Common Units or result in audit adjustments to the Unitholder s tax returns.

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Unitholders likely will be subject to state and local taxes in states where they do not live as a result of an investment in the units.

In addition to federal income taxes, the Unitholders may be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property now or in the future, even if they do not live in any of those jurisdictions. We presently have business operations in 41 states. In the future, we may acquire property or do business in other states or in foreign jurisdictions. Unitholders may be required to file state and local income tax returns and pay state and local income taxes in some or all of the jurisdictions. Further, Unitholders may be subject to penalties for failure to comply with those requirements. It is the responsibility of each Unitholder to file all federal, state and local tax returns. Our counsel has not rendered an opinion on the state or local tax consequences of an investment in us.

The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the termination of our partnership for federal income tax purposes.

We will be considered to have terminated for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. Our termination would, among other things, result in the closing of our taxable year for all Unitholders and could result in a deferral of depreciation deductions allowable in computing our taxable income.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

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

Some of the leases, easements, rights-of-way, permits, licenses and franchise ordinances that will be transferred to us will require the consent of the current landowner to transfer these rights, which in some instances is a governmental entity. We believe that we have obtained or will obtain sufficient third-party consents, permits and authorizations for the transfer of the assets necessary for us to operate our business in all material respects. With respect to any consents, permits or authorizations that have not been obtained, we believe that these consents, permits or authorizations will be obtained, or that the failure to obtain these consents, permits or authorizations will have no material adverse effect on the operation of our business.

We own two office buildings for our executive offices in Dallas, Texas and one office building in Helena, Montana for the administration of our propane operations. We also lease office facilities in Houston, Texas, San Antonio, Texas, and Tulsa, Oklahoma. While we may require additional office space as our business expands, we believe that our existing facilities are adequate to meet our needs for the immediate future, and that additional facilities will be available on commercially reasonable terms as needed.

We operate bulk storage facilities at 442 customer service locations for our propane operations. We own substantially all of these facilities and have entered into long-term leases for those that we do not own. We believe that the increasing difficulty associated with obtaining permits for new propane distribution locations makes our high level of site ownership and control a competitive advantage. We own approximately 48.0 million gallons of aboveground storage capacity at our various propane plant sites and have leased an aggregate of approximately 35.3 million gallons of underground storage facilities in Michigan, Arizona, New Mexico and Texas and smaller storage facilities in other locations. We do not own or operate any underground propane storage facilities (excluding customer and local distribution tanks) or propane pipeline transportation assets (other than local delivery systems).

The transportation of propane requires specialized equipment. The trucks and railroad tank cars used for this purpose carry specialized steel tanks that maintain the propane in a liquefied state. As of August 31, 2006, we utilized approximately 68 transport truck tractors, 68 transport trailers, 15 railroad tank cars, 1,772 bobtails and 2,831 other delivery and service vehicles, all of which we own. As of August 31, 2006, we owned approximately 1,135,800 customer storage tanks with typical capacities of 120 to 1,000 gallons that are leased or available for lease to customers. HOLP s customer storage tanks are pledged as collateral to secure the obligations of HOLP to its banks and the holders of its notes.

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We utilize a variety of trademarks and trade names in our propane operations that we own or have secured the right to use, including Heritage Propane and Titan Propane . These trademarks and trade names have been registered or are pending registration before the United States Patent and Trademark Office or the various jurisdictions in which the trademarks or trade names are used. We believe that our strategy of retaining the names of the companies we have acquired has maintained the local identification of these companies and has been important to the continued success of these businesses. Some of our most significant trade names include Balgas, Bi-State Propane, Blue Flame Gas of Charleston, Blue Flame Gas of Mt. Pleasant, Blue Flame Gas, Carolane Propane Gas, Gas Service Company, EnergyNorth Propane, Gibson Propane, Guilford Gas, Holton s L.P. Gas, Ikard & Newsom, Northern Energy, Sawyer Gas, ProFlame, Rural Bottled Gas and Appliance, ServiGas, V-1 Propane, Coast Gas, Empiregas, Flame Propane, Graves Propane, Synergy Gas. We regard our trademarks, trade names and other proprietary rights as valuable assets and believe that they have significant value in the marketing of our products.

We believe that we have satisfactory title to or valid rights to use all of our material properties. Although some of our properties are subject to liabilities and leases, liens for taxes not yet due and payable, encumbrances securing payment obligations under non-competition agreements and immaterial encumbrances, easements and restrictions, we do not believe that any such burdens will materially interfere with our continued use of such properties in our business, taken as a whole. In addition, we believe that we have, or are in the process of obtaining, all required material approvals, authorizations, orders, licenses, permits, franchises and consents of, and have obtained or made all required material registrations, qualifications and filings with, the various state and local government and regulatory authorities which relate to ownership of our properties or the operations of our business.

ITEM 3. LEGAL PROCEEDINGS

Although our Operating Partnerships may, from time to time, be involved in litigation and claims arising out of operations in the normal course of their businesses, such Operating Partnerships are not currently a party to any material legal proceedings. In addition, we are not aware of any material legal or governmental proceedings against our Operating Partnerships, or contemplated to be brought against our Operating Partnerships, under the various environmental protection statutes to which they are subject.

At the time of the HPL acquisition, the HPL Entities, their parent companies and AEP, were engaged in ongoing litigation with Bank of America (B of A) that related to AEP s acquisition of HPL in the Enron bankruptcy and B of A s financing of cushion gas stored in the Bammel Storage facility (Cushion Gas). This litigation is referred to as the Cushion Gas Litigation . Under the terms of the Purchase and Sale Agreement and the related Cushion Gas Litigation Agreement, AEP and its subsidiaries that were the sellers of the HPL Entities retained control of the Cushion Gas Litigation and have agreed to indemnify ETC OLP and the HPL Entities for any damages arising from the Cushion Gas Litigation and the loss of use of the Cushion Gas, up to a maximum of the amount paid by ETC OLP for the HPL Entities and the working gas inventory. The Cushion Gas Litigation Agreement terminates upon final resolution of the Cushion Gas Litigation. In addition, under the terms of the Purchase and Sale Agreement, AEP retained control of additional matters relating to ongoing litigation and environmental remediation and agreed to bear the costs of or indemnify ETC OLP and the HPL Entities for the costs related to such matters.

HOLP received favorable final judgment with respect to the SCANA litigation on all four claims on October 21, 2004, and received $7.7 million in net settlement proceeds on June 1, 2006 (See Note 9 to our consolidated financial statements).

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We or our subsidiaries are a party to various legal proceedings and/or regulatory proceedings incidental to our businesses. Certain claims, suits and complaints arising in the ordinary course of business have been filed or are pending against us. Although any litigation is inherently uncertain, based on past experience, the information currently available and the availability of insurance coverage, and in the opinion of management, all such matters are either covered by insurance, are without merit or involve amounts, which, if resolved unfavorably, may have a significant effect on the results of operations for a single period. However, we believe that such matters will not have a material adverse effect on our financial position. Once management determines that information pertaining to a legal proceeding indicates that it is probable that a liability has been incurred, an accrual is established equal to management s estimate of the likely exposure. For matters that are covered by insurance, we accrue the related deductible.

As of August 31, 2006 and 2005, an accrual of $32.1 million and $1.1 million, respectively, was recorded as accrued and other current liabilities on our consolidated balance sheets for our contingencies and current litigation matters, excluding accruals related to environmental matters. (See Note 9 to our consolidated financial statements.)

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

On August 15, 2006, we held a special meeting for our Common Unitholders of record on July 20, 2006. At the meeting, our Common Unitholders approved the change in the terms and conversion of all 2,570,150 outstanding Class F Units into 2,570,150 Common Units. The outcome of the vote to approve a change in the terms of our Class F Units to provide that each Class F Unit convert into one of our Common Units was 63,952,207 for, 672,615 against, 386,737 abstentions, and 43,145,290 broker and all other non-votes.

PART II

ITEM 5. MARKET FOR THE REGISTRANT S COMMON UNITS, RELATED UNITHOLDER

MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Market Price of and Distributions on the Common Units and Related Unitholder Matters

Our Common Units are listed on the New York Stock Exchange under the symbol ETP . The following table sets forth, for the periods indicated, the high and low sales prices per Common Unit, as reported on the New York Stock Exchange Composite Tape, and the amount of cash distributions paid per Common Unit for the periods indicated. The table reflects the effect of the two-for-one unit split on March 15, 2005.

	Price Range		Cash
	High	Low	Distribution (1)
2006 Fiscal Year			
Fourth Quarter Ended August 31, 2006	$ 48.00	$ 42.02	$ 0.75000
Third Quarter Ended May 31, 2006	$ 45.85	$ 35.31	$ 0.63750
Second Quarter Ended February 28, 2006	$ 37.98	$ 33.55	$ 0.58750
First Quarter Ended November 30, 2005	$ 37.72	$ 30.53	$ 0.55000

	Price Range		Cash
	High	Low	Distribution
2005 Fiscal Year			
Fourth Quarter Ended August 31, 2005	$ 39.09	$ 31.69	$ 0.50000
Third Quarter Ended May 31, 2005	$ 33.13	$ 28.54	$ 0.48750
Second Quarter Ended February 29, 2005	$ 32.69	$ 25.59	$ 0.46250
First Quarter Ended November 30, 2004	$ 27.37	$ 21.51	$ 0.43750

(1) Distributions are shown in the quarter with respect to which they were declared. For each of the indicated quarters for which distributions have been made, an identical per unit cash distribution was paid on any units subordinated to our Common Units outstanding at such time. Please see Cash Distribution Policy for a discussion of our policy regarding the payment of distributions.

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On June 20, 2006, we declared a special distribution of $0.0325 per Limited Partner Unit related to the proceeds received by the Partnership in connection with the SCANA litigation settlement (see Notes 6 and 9 to the consolidated financial statements) which was paid on July 14, 2006 to the holders of record of the Partnership s Common and Class F Units as of the close of business on June 30, 2006 for the third quarter ended May 31, 2006.

Description of Units

As of September 30, 2006, there were approximately 67,574 individual Common Unitholders, which includes Common Units held in street name. Our Common Units represent limited partner interests in our Amended and Restated Agreement of Limited Partnership, as amended to date (the Partnership Agreement) that entitle the holders to the rights and privileges specified in the Partnership Agreement.

Common Units. As of August 31, 2006, we had 110,726,999 Common Units outstanding, of which 72,504,823 were held by the public, 36,413,840 were held by ETE or its affiliates, 1,308 were held by FHM Investments, L.L.C., and 1,807,028 were held by our officers and directors. As of such date, the Common Units represent an aggregate 98.0% limited partner interest in us. Our General Partner owns an aggregate 2.0% general partner interest in us. Our Common Units are registered under the Securities Exchange Act of 1934, as amended and are listed for trading on the New York Stock Exchange (the NYSE). The Common Units are entitled to distributions of Available Cash as described below under Cash Distribution Policy.

Class C Units. Prior to the payment of a one-time special distribution on July 14, 2006, we had 1,000,000 Class C Units outstanding, all of which were held by FHS Investments, L.L.C. Upon making the payment to the holder of the Class C Units on July 14, 2006, all 1,000,000 outstanding Class C Units were retired and canceled. See Note 6 Partners Capital and Unit Based Compensation Plans to the consolidated financial statements beginning in Item 8 of this report for further discussion of the Class C Units.

Class D Units. The Class D Units were issued to ETE in the Energy Transfer Transactions. We were required, as promptly as practicable following the issuance of the Class D Units, to submit to a vote of our Unitholders a change in the terms of the Class D Units to provide that each Class D Unit would convert into one Common Unit immediately upon such approval. Our Unitholders approved this change in the terms of the Class D Units on June 23, 2004 at a special meeting of the Common Unitholders. Pursuant to the request of the holders of the Class D Units, these Class D Units were converted to an equal number of Common Units on June 24, 2004, and no Class D Units are outstanding.

Class E Units. In conjunction with our purchase of the capital stock of Heritage Holdings in January 2004, the 4,426,916 Common Units held by Heritage Holdings were converted into 4,426,916 Class E Units. Pursuant to our two-for-one unit split completed on March 15, 2005, there are currently 8,853,832 Class E Units outstanding, all of which are owned by Heritage Holdings. The Class E Units generally do not have any voting rights. These Class E Units are entitled to aggregate cash distributions equal to 11.1% of the total amount of cash distributed to all Unitholders, including the Class E Unitholders, up to $1.41 per unit per year. Management plans to leave the Class E Units in the form described here indefinitely.

Class F Units. On February 28, 2006, we issued 2,570,150 Class F Units representing limited partnership interests in the Partnership to ETE in a private placement for $132.4 million. The terms and provisions of the Class F Units provided that they may be converted to Common Units upon the approval of a majority of the holders of our Common Units. Prior to conversion of the Class F Units, the Class F Units shared in Partnership distributions and were entitled to all items of Partnership income, gain, loss, deduction and credit as if the Class F Units were Subordinated Units. Upon receiving the requisite approval by our Common Unitholders under a proposal to convert the Class F Units to Common Units, all Class F Units were to convert to Common Units on a one-for-one basis. On August 15, 2006 at a special meeting, our Common Unitholders approved a proposal to change the terms of our Class F units to provide that each Class F Unit is convertible into one of our Common Units and to issue the additional Common Units upon such conversion. On August 16, 2006 all the Class F Units were converted to Common Units and ceased to have the right to participate in distributions of available cash.

Class G Units. See Note 16 to our consolidated financial statements for a discussion of our Class G Units issued on November 1, 2006.

Special Units. In January 2004, 7,485,030 Special Units were issued to ETE in the Energy Transfer Transactions as consideration for the East Texas Pipeline. Following Unitholder approval at a special meeting of the Unitholders on June 23, 2004 and upon the East Texas Pipeline becoming commercially operational on June 21, 2004, each Special Unit converted into one Common Unit on June 24, 2004 upon the request of the holder and no Special Units are outstanding.

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Incentive Distribution Rights. Incentive Distribution Rights represent the contractual right to receive a specified percentage of quarterly distributions of Available Cash from operating surplus after the minimum quarterly distribution has been paid. Please read Quarterly Distributions of Available Cash below. Subsequent to the retirement of the 1,000,000 Class C Units, the General Partner owns all of the Incentive Distribution Rights.

Cash Distribution Policy

General. We will distribute all of our Available Cash to our Unitholders and our General Partner within 45 days following the end of each fiscal quarter.

Definition of Available Cash. Available Cash is defined in our Partnership Agreement and generally means, with respect to any calendar quarter, all cash on hand at the end of such quarter:

- Less the amount of cash reserves that are necessary or appropriate in the reasonable discretion of the General Partner to:
  - provide for the proper conduct of our business;
  - comply with applicable law or and debt instrument or other agreement (including reserves for future capital expenditures and for our future capital needs); or
  - provide funds for distributions to Unitholders and our General Partner in respect of any one or more of the next four quarters.
- Plus all cash on hand on the date of determination of Available Cash for the quarter resulting from working capital borrowings made after the end of the quarter. Working capital borrowings are generally borrowings that are made under our credit facilities and in all cases are used solely for working capital purposes or to pay distributions to partners.

Available Cash is more fully defined in the Partnership Agreement previously filed as an exhibit.

Operating Surplus and Capital Surplus

General. All cash distributed to our Unitholders is characterized as either operating surplus or capital surplus . We distribute available cash from operating surplus differently than available cash from capital surplus.

Definition of Operating Surplus. Our operating surplus for any period generally means:

- our cash balance on the closing date of our initial public offering in 1996; plus
- $10.0 million (as described below); plus
- all of our cash receipts since the closing of our initial public offering, excluding cash from interim capital transactions such as borrowings that are not working capital borrowings, sales of equity and debt securities and sales or other dispositions of assets outside the ordinary course of business; plus

our working capital borrowings made after the end of a quarter but before the date of determination of operating surplus for the quarter; less

all of our operating expenditures after the closing of our initial public offering, including the repayment of working capital borrowings, but not the repayment of other borrowings, and including maintenance capital expenditures; less

the amount of our cash reserves that our General Partner deems necessary or advisable to provide funds for future operating expenditures.

Definition of Capital Surplus. Generally, our capital surplus will be generated only by:

borrowings other than working capital borrowings;

sales of our debt and equity securities; and

sales or other disposition of assets for cash, other than inventory, accounts receivable and other current assets sold in the ordinary course of business or as part of normal retirements or replacements of assets.

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Characterization of Cash Distributions. We will treat all Available Cash distributed as coming from operating surplus until the sum of all Available Cash distributed since we began operations equals the operating surplus as of the most recent date of determination of Available Cash. We will treat any amount distributed in excess of operating surplus, regardless of its source, as capital surplus. As defined in our Partnership Agreement, operating surplus includes $10.0 million in addition to our cash balance on the closing date of our initial public offering, cash receipts from our operations and cash from working capital borrowings. This amount does not reflect actual cash on hand that is available for distribution to our Unitholders. Rather, it is a provision that will enable us, if we choose, to distribute as operating surplus up to $50.0 million of cash we receive in the future from non-operating sources, such as asset sales, issuances of securities, and long-term borrowings, that would otherwise be distributed as capital surplus. We have not made, and we anticipate that we will not make, any distributions from capital surplus.

Distributions of Available Cash from Operating Surplus

We are required to make distributions of Available Cash from operating surplus for any quarter in the following manner:

First, 98% to all Common, Class E and Class F Unitholders, in accordance with their percentage interests, and 2% to the General Partner, until each Common Unit has received $0.25 per unit for such quarter (the minimum quarterly distribution);

Second, 98% to all Common, Class E and Class F Unitholders, in accordance with their percentage interests, and 2% to the General Partner, until each Common Unit has received $0.275 per unit for such quarter (the first target cash distribution);

Third, 85% to all Common, Class E and Class F Unitholders, in accordance with their percentage interests, 13% to the holders of Incentive Distribution Rights, pro rata, and 2% to the General Partner, until each Common Unit has received at least $0.3175 per unit for such quarter (the second target cash distribution);

Fourth, 75% to all Common, Class E and Class F Unitholders, in accordance with their percentage interests, 23% to the holders of Incentive Distribution Rights, pro rata, and 2% to the General Partner, until each Common Unit has received at least $0.4125 per unit for such quarter (the third target cash distribution); and

Fifth, thereafter, 50% to all Common, Class E and Class F Unitholders, in accordance with their percentage interests, 48% to the holders of Incentive Distribution Rights, pro rata, and 2% to the General Partner.

Notwithstanding the foregoing, any arrearage in the payment of the minimum quarterly distribution for all prior quarters and the distributions on each Class E unit may not exceed $1.41 per year.

Distributions of Available Cash from Capital Surplus

We will make distributions of available cash from capital surplus, if any, in the following manner:

First , 98% to all of our Unitholders, pro rata, and 2% to our General Partner, until we distribute for each Common Unit, an amount of available cash from capital surplus equal to our initial public offering price; and

Thereafter, we will make all distributions of available cash from capital surplus as if they were from operating surplus.

Our Partnership Agreement treats a distribution of capital surplus as the repayment of the initial unit price from the initial public offering, which is a return of capital. The initial public offering price per Common Unit less any distributions of capital surplus per unit is referred to as the unrecovered capital .

If we combine our units into fewer units or subdivide our units into a greater number of units, we will proportionately adjust our minimum quarterly distribution; our target cash distribution levels; and our unrecovered capital.

For example, if a two-for-one split of our Common Units should occur, our unrecovered capital would each be reduced to 50% of our initial level. We will not make any adjustment by reason of our issuance of additional units for cash or property.

On January 14, 2005, our General Partner announced a two-for-one split of our Common Units that was effected on March 15, 2005. As a result, our minimum quarterly distribution and the target cash distribution levels were reduced to 50% of their initial levels. Our adjusted minimum quarterly distribution and the adjusted target cash distribution levels are reflected in the discussion above under the caption Distributions of Available Cash from Operating Surplus.

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In addition, if legislation is enacted or if existing law is modified or interpreted in a manner that causes us to become taxable as a corporation or otherwise subject to taxation as an entity for federal, state or local income tax purposes, we will reduce our minimum quarterly distribution and the target cash distribution levels by multiplying the same by one minus the sum of the highest marginal federal corporate income tax rate that could apply and any increase in the effective overall state and local income tax rates.

The total amount of distributions declared relating to the years ended August 31, 2006 and 2005 is as follows:

	2006	2005
Limited Partners -		
Common Units	$ 248,237	$ 173,802
Class D Units		
Class C Units	3,599	
Class F Units	3,232	
General Partner -		
2% Ownership	6,981	4,390
Incentive Distribution Rights	81,722	28,847
Total distributions declared	$ 343,771	$ 207,039

All distributions were made from Available Cash from the Partnership s operating surplus.

Securities authorized for issuance under equity compensation plans

Please see Item 12, Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters of this annual report.

Changes in Securities and Recent Sales of Unregistered Securities

None other than the Class F Units, as discussed above.

ITEM 6. SELECTED FINANCIAL DATA

Although Heritage Propane Partners, L.P. was the surviving parent entity for legal purposes in the Energy Transfer Transactions, ETC OLP was the acquirer for accounting purposes. As a result, following the Energy Transfer Transactions in January 2004, the historical financial statements of ETC OLP for periods prior to the closing of the Energy Transfer Transactions became our historical financial statements. ETC OLP was formed on October 1, 2002 and has an August 31 year-end. ETC OLP s predecessor entities had a December 31 year-end.

In April 2005, we sold the Elk City System and accounted for the sale as discontinued operations. As such, the results presented for the period from October 1, 2002 to August 31, 2004 below have been restated to account for the results of the Elk City System in discontinued operations.

ETC OLP s historical financial information for periods prior to October 1, 2002 has been derived from the historical financial statements of Aquila Gas Pipeline. Prior to October 1, 2002, Aquila Gas Pipeline owned the Southeast Texas System, the Elk City System and a 50% equity interest in Oasis Pipe Line. All of these assets were acquired by ETC OLP effective October 1, 2002.

The financial information below for Aquila Gas Pipeline as of and for the nine months ended September 30, 2002 and as of and for the year ended December 31, 2001 has been derived from the audited consolidated financial statements of Aquila Gas Pipeline, which are not included in this report, but were included in previous filings.

The selected historical financial data should be read in conjunction with the financial statements of Energy Transfer Partners, L.P. included elsewhere in this report and with Management s Discussion and Analysis of Financial Condition and Results of Operations included in this report. The amounts in the table below, except per unit data, are in thousands.

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	Aquila Gas Pipeline Year Ended December 31, 2001	Nine Months Ended September 30, 2002	Eleven Months Ended August 31, 2003 (a)	Energy Transfer Partners Year Ended August 31, 2004	2005	2006
Statement of Operations Data:						
Revenues						
Midstream segment	$ 1,813,850	$ 933,099	$ 899,086	$ 1,880,663	$ 3,246,772	$ 4,223,544
Transportation and storage segment			41,500	113,938	2,608,108	5,013,224
Eliminations			(9,559)	(27,798)	(471,255)	(2,359,256)
Propane segments				376,689	778,306	973,844
Other segment				3,465	6,867	7,740
Total revenues	1,813,850	933,099	931,027	2,346,957	6,168,798	7,859,096
Gross margin	98,589	53,035	105,589	365,533	787,283	1,290,780
Depreciation and amortization	30,779	22,915	11,870	48,599	92,943	117,415
Operating income	42,990	2,862	55,595	139,089	312,051	642,871
Interest expense	6,858	3,931	12,456	41,190	93,017	113,857
Income from continuing operations before income tax expense	41,161	4,272	45,063	97,470	208,678	541,772
Income tax expense (benefit) (b)	15,403	(467)	4,432	4,481	7,295	25,920
Income from continuing operations	25,758	4,739	40,631	92,989	201,383	515,852
Basic net income from continuing operations per unit (c)			3.01	1.62	1.51	3.16
Diluted net income from continuing operations per unit (c)			3.01	1.62	1.50	3.15
Cash distribution per unit (d)				1.46	1.89	2.56
Balance Sheet Data (at period end):						
Current assets	144,396	116,831	223,897	480,435	1,446,572	1,301,804
Total assets	633,260	601,528	602,103	2,327,104	4,415,458	5,455,013
Current liabilities	194,816	144,076	169,473	397,037	1,239,426	1,016,490
Long-term debt	66,250	66,250	196,000	1,070,871	1,675,705	2,589,124
Stockholders equity/Partners capital	249,520	254,259	181,088	746,980	1,326,192	1,736,862
Other Financial Data:						
Cash flow provided by operating activities	65,198	12,987	70,206	162,695	169,418	543,884
Cash flow used in investing activities	(20,727)	(487)	(341,258)	(790,737)	(1,133,749)	(1,244,406)
Cash flow provided by (used in) financing activities	(44,471)	(12,500)	324,174	656,665	907,500	701,649
Capital expenditures						
Maintenance and growth	23,944	5,486	11,914	109,688	196,459	680,164
Acquisition			340,187	681,835	1,131,844	586,185

(a) On December 27, 2002, ETC OLP purchased the remaining 50% of Oasis Pipe Line. Prior to December 27, 2002, the interest in Oasis Pipe Line was treated as an equity method investment. After that date, Oasis Pipe Line s results of operations are consolidated with ETC OLP as a wholly-owned subsidiary.

(b)

As a partnership, we are not subject to income taxes. However, our subsidiaries, Oasis Pipe Line, Heritage Holdings, Heritage Service Corporation, and Titan Propane Services, Inc. are corporations that are subject to income taxes. Prior to 2003, Oasis Pipe Line was an equity method investment of ETC OLP, and taxes were netted against the equity method earnings. Aquila Gas Pipeline was a tax-paying corporation, and as such recognized income taxes related to its earnings in all periods presented.

(c) Basic net income per limited partner unit is computed in accordance with EITF Issue No. 03-6, *Participating Securities and the Two-Class method under FASB Statement No. 128* (EITF 03-6), by dividing limited partners interest in net income by the weighted average number of Common and Class F Units outstanding. In periods when our aggregate net income exceeds the aggregate distributions, EITF 03-6 requires us to present earnings per unit as if all of the earnings for the periods were distributed and requires a separate computation for each quarter and year-to-date. Diluted net income per limited partner unit is computed by dividing limited partners interest in net income, after considering the General Partner s interest, by the weighted average number of Common and Class F Units outstanding and the effect of non-vested restricted units (Unit Grants) granted under the 2004 Unit Plan and predecessor plan computed using the treasury stock method.

(d) The cash distribution per unit for fiscal year 2006 includes the Special SCANA distribution of $0.0325 per unit discussed in Item 3 Legal Proceedings of this Annual Report on Form 10-K.

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ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION

AND RESULTS OF OPERATIONS

Our Management s Discussion and Analysis includes forward-looking statements that are subject to risk and uncertainties. Actual results may differ substantially from the statements we make in this section due to a number of factors that are discussed in Item 1A Risk Factors included in this report.

Overview

General

Energy Transfer Partners, L.P. (the Registrant or Partnership), is a Delaware Limited Partnership. Our Common Units are listed on the New York Stock Exchange under the symbol ETP . Our business activities are primarily conducted through our subsidiaries, ETC OLP, a Texas limited partnership, HOLP, a Delaware Limited Partnership and Titan, a Delaware Limited Partnership, (collectively, the Operating Partnerships). The Partnership and the Operating Partnerships are sometimes referred to collectively in this report as we , us , Energy Transfer or ETP .

Our primary objective is to increase the level of our cash distributions over time by pursuing a business strategy that is currently focused on growing our natural gas midstream and transportation and storage businesses (including transportation, gathering, compression, treating, processing, storage and marketing) and our propane business through, among other things, pursuing certain construction and expansion opportunities relating to our existing infrastructure and acquiring certain additional businesses or assets. The actual amount of cash that we will have available for distribution will primarily depend on the amount of cash we generate from operations.

During the past several years we have been successful in completing several transactions that have been accretive to our Unitholders. First and foremost was the combination of the retail propane operations of HOLP and the midstream and transportation and storage operations of ETC OLP in January 2004. Subsequent to the combination we have made numerous acquisitions in both the natural gas and propane operations, including the acquisition of the ET Fuel System, Houston Pipeline System (HPL) and Titan. We have also recently announced the pending acquisition of Transwestern Pipeline. Concurrently, we have also made significant investments in internal growth projects which we believe will provide additional cash flow to our Unitholders in years to come.

Midstream and Transportation and Storage Segments

Through ETC OLP, we own the largest intrastate pipeline system in the United States with interconnects to major consumption areas throughout the United States. The midstream and transportation and storage operations accounted for approximately 90% of our consolidated operating income for the year ended August 31, 2006.

Our midstream segment results are derived primarily from margins we realize for natural gas volumes that are gathered, transported, purchased and sold through our pipeline systems, processed at our processing and treating facilities, and the volumes of NGLs processed at our facilities. We also market natural gas on our pipeline systems in addition to other pipeline systems to realize incremental revenue on gas purchased, increase pipeline utilization and provide other services that are valued by our customers. In addition and in accordance with our commodity risk management policy, we generate income from limited trading activities. Our trading activities include purchasing and selling natural gas and the use of financial instruments, including basis and gas daily contracts.

Our transportation and storage segment consists of natural gas gathering and intrastate transportation pipelines as well as three natural gas storage facilities with approximately 78 Bcf in storage capacity. The results from our transportation and storage segment are primarily derived from the fees we charge to transport natural gas on our pipelines, including a fuel retention component. We also generate revenues and margin from the sale of natural gas to electric utilities, independent power plants, local distribution companies, industrial end-users, and other marketing companies on the HPL System. Generally, HPL purchases its natural gas from either the market (including purchases from our midstream segment s producer services) and from producers at the wellhead. To the extent the natural gas comes from producers, it is purchased at a discount to a specified price and resold to customers at the index price.

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We also utilize our Bammel storage reservoir to engage in natural gas storage transactions in which we seek to find and profit from pricing differences that occur over time. We purchase physical natural gas and then sell financial contracts at a price sufficient to cover our carrying costs and provide for a gross profit margin.

As a result of our trading activities and the use of derivative financial instruments that may not qualify for hedge accounting in our midstream and transportation and storage segments, the degree of earnings volatility that can occur may be significant, favorably or unfavorably, from period to period. We attempt to manage this volatility through the use of daily position and profit and loss reports provided to our risk management committee, which includes members of senior management, and predefined limits and authorizations set forth by our risk management policy. See further discussion regarding our risk management policies in Item 7A Quantitative and Qualitative Disclosures about Market Risk found elsewhere in this report.

Retail and Wholesale Propane segments

Our propane-related segments are operated by HOLP, Titan and their respective subsidiaries engaged in the sale, distribution and marketing of propane and other related products through our retail and wholesale segments, (the propane segments). HOLP and Titan derive their revenue primarily from the retail propane segment. We believe that we are the third largest retail propane marketer in the United States, based on retail gallons sold. We serve more than 1,000,000 propane customers from 442 customer service locations in 41 states. Collectively, our propane-related segments accounted for approximately 12% of our consolidated operating income for the year ended August 31, 2006.

The propane segments are margin-based businesses in which gross profits depend on the excess of sales price over propane supply cost. The market price of propane is often subject to volatile changes as a result of supply or other market conditions over which we have no control. Product supply contracts are generally one-year agreements subject to annual renewal and generally permit suppliers to charge posted prices (plus transportation costs) at the time of delivery or the current prices established at major delivery points. Since rapid increases in the wholesale cost of propane may not be immediately passed on to retail customers, such increases could reduce gross profits. We generally have attempted to reduce price risk by purchasing propane on a short-term basis. We have on occasion purchased for future resale significant volumes of propane for storage during periods of low demand, which generally occur during the summer months, at the then current market price, both at our customer service locations and in major storage facilities. In particular, our propane business is largely seasonal and dependent upon weather conditions in our service areas.

Historically, approximately two-thirds of our retail propane volume and substantially all of our propane-related operating income, is attributable to sales during the six-month peak-heating season of October through March. This generally results in higher operating revenues and net income in the propane segments during the period from October through March of each year, and lower operating revenues and either net losses or lower net income during the period from April through September of each year. Consequently, sales and operating profits for the propane segments are concentrated in our first and second fiscal quarters; however, cash flow from operations is generally greatest during our second and third fiscal quarters when customers pay for propane purchased during the six-month peak-heating season. Sales to industrial and agricultural customers are much less weather sensitive.

A substantial portion of our propane is used in the heating-sensitive residential and commercial markets causing the temperatures in our areas of operations, particularly during the six-month peak-heating season, to have a significant effect on the financial performance of our propane operations. In any given area, sustained warmer-than-normal temperatures will tend to result in reduced propane use, while sustained colder-than-normal temperatures will tend to result in greater propane use. We use information about normal temperatures to help us understand how temperatures that are colder or warmer than normal affect historical results of operations and in preparing forecasts related to our future operations.

The retail propane segment s gross profit margins are not only affected by weather patterns, but also vary according to customer mix. Sales to residential customers generate higher margins than sales to certain other customer groups, such as commercial or agricultural customers. The wholesale propane segment s margins are substantially lower than retail margins. In addition, propane gross profit margins vary by geographical region. Accordingly, a change in customer or geographic mix can affect propane gross profit without necessarily affecting total revenues.

Amounts discussed below reflect 100% of the results of MP Energy Partnership. MP Energy Partnership is a Canadian general partnership in which HOLP owns a 60% interest.

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Summary of Operating Financial Performance in fiscal 2006

During the fiscal year ended August 31, 2006, we experienced record results in a volatile energy market caused by two hurricanes that hit the Texas and Louisiana coastlines and a warmer than normal winter. Prior to fiscal year 2006 we completed a number of acquisitions mainly in the midstream and transportation and storage operations and have been able to successfully integrate them into our existing pipeline systems. The integration and realized synergies allowed our pipeline systems to deliver strong financial results. We also added approximately 81,000 horsepower of compression during the year which allowed us to transport more natural gas on our pipelines.

The industry also experienced higher commodity prices. NYMEX prices for the prompt month settlement averaged $8.95 during the year ended August 31, 2006 compared to an average price of $7.05 during fiscal year 2005. Higher natural gas prices tend to promote shippers to transport natural gas to more liquid markets. In addition, we experienced improved price differentials between the west and east Texas market hubs and better than expected processing margins towards the latter half of our fiscal year which allowed us to realize higher margins in our midstream and transportation and storage operations.

Despite the warmer than normal winter, our propane operations were able to deliver higher than expected results. Our retail volumes increased as a result of the Titan and other acquisitions during fiscal years 2006 and 2005 which offset the decrease in volumes we experienced due to the warmer weather. We also were able to increase our sales prices which improved our gross margins. Additionally, due to the acquisitions we made during fiscal years 2006 and 2005, our other propane segment revenues, such as appliance sales, labor and tank rentals, also improved over prior years.

Trends and Outlook

While there were certain anomalies that impacted our fiscal 2006 results, we believe our operations are again positioned to provide increasing operating results based on the current levels of contracted and expected capacity to be taken by our customers, our expansion plans that we expect to complete in fiscal year 2007, and our recently acquired Titan operations. We also expect to complete the acquisition of Transwestern Pipeline in the second quarter of fiscal year 2007, and upon closing, we expect the transaction to be immediately accretive to our Common Unitholders.

Natural gas prices have decreased since August 2006. To the extent natural gas prices remain low our strategy to execute more fee-based contracts will allow us to continue to meet our cash obligations. Our ownership of the Bammel storage facility has also allowed us to hedge the purchase and sale of natural gas at favorable margin levels.

We also expect our propane-related segment to realize overall volume increases during fiscal year 2007 due to the effects of the Titan acquisition. However, continued warmer than normal weather will negatively impact volumes. We expect to be able to offset the impact of weather-related reduced volumes with reduced operating costs and improved gross margins to the extent our marketplace will allow it. We also plan to continue our active propane acquisition strategy and to expand our internal growth initiatives.

Recent Expansion Projects

42-inch project. On August 31, 2006 we announced the completion of the first phase of our previously announced 42-inch pipeline construction project. This segment, comprised of 97 miles of 42-inch natural gas pipeline, connects our 30-inch pipeline in Freestone County, the Bethel Storage Facility and our 30-inch Texoma pipeline in Rusk County. This portion of the 42-inch project has been placed in service and is currently flowing natural gas. The completion of this first phase provides us with additional take-away capacity to transport gas out of the Barnett Shale and Bossier Sands producing areas.

The full benefit of our 42-inch construction project will be recognized upon completion of the additional phases, all of which are currently underway and are on schedule to be completed by March 2007. Because of our increased transportation commitments, our Board of Directors approved a plan to upsize the recently announced 157-mile, 36-inch expansion of this project to 42-inch for the section that runs from Limestone County, Texas to the interconnect with our Texoma pipeline, northeast of Beaumont. The increased upsizing will bring the estimated total cost of the project from $895.0 million to approximately $1.0 billion.

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Transwestern Pipeline. On September 15, 2006, we announced the execution of agreements with GE Energy Financial Services (GE) and Southern Union Company to acquire the Transwestern Pipeline, a 2,500 mile interstate natural gas pipeline. The agreements provide for a series of transactions in which we will acquire all of the member interests in CCE Holding, LLC (CCEH) owned by GE and certain other investors. The member interests acquired will represent a 50% ownership in CCEH, which was formed in 2004 to purchase CrossCountry Energy. In the second transaction, CCEH will redeem our 50% ownership of CCEH of the Partnership in exchange for 100% ownership of Transwestern Pipeline Company, LLC (Transwestern), following which Southern Union will own all of the member interests of CCEH.

The Transwestern Pipeline connects supply areas in the San Juan Basin in southern Colorado and northern New Mexico, the Anadarko Basin in the Mid-continent and the Permian Basin in west Texas to markets in the Midwest, Texas, Arizona, New Mexico and California. The Transwestern Pipeline interconnects with our existing intrastate pipelines in west Texas. The combination of pipeline systems will result in new market opportunities for existing natural gas supply sources on both systems and increases supply availability and flexibility to existing markets served by both systems. On November 1, 2006 we acquired the member interests in CCEH from GE and certain other investors for $1 billion and expect to complete the remaining series of transactions in the second quarter of fiscal year 2007. We financed the purchase price with our issuance of approximately 26.1 million Class G Units issued to ETE simultaneous with the closing.

Johnson County processing plant. The processing facility is being built in two phases to process rich natural gas produced from the Barnett Shale and will connect with our existing pipeline infrastructure. Phase I consists of a cryogenic gas plant with capacity of 115 MMcf/d, which is expected to be in service by the end of November 2006. Phase II of the project includes another 170 MMcf/d cryogenic gas plant and a 100 MMcf/d hydrocarbon dew point refrigeration plant, and is expected to be completed by the end of June 2007. The facility is being built to accommodate additional expansion in the future. The facility will be one of the few North Texas natural gas processing plants with access to two NGL pipeline outlets. The cost for this project is approximately $65.0 million.

36-inch pipeline expansion. The expansion is the result of our continued success in contracting transportation volumes. This 135-mile pipeline connects our existing Fort Worth Basin system to our 30-inch Texoma pipeline in Lamar County, Texas. The project expands producer s options by providing additional market opportunities including the Carthage hub, interstate pipelines and industrial users along the Houston Ship Channel. It includes 27 miles of 30-inch pipe and 64,000 horsepower of compression with an initial capacity of 700 MMcf/d with expansion capabilities up to 1.0 Bcf/d. This expansion project will cost approximately $300.0 million.

Gathering Systems. We also acquired two small gathering systems in east and north Texas for an aggregate purchase price of $30.0 million. The purchase and sale agreement for the gathering system in north Texas also has a contingent payment not to exceed $25.0 million to be determined eighteen months from the closing date. These systems provide additional capacity in the Barnett Shale and in east Texas.

Analytical Analysis

The following is a discussion of our historical financial condition and results of operations, and should be read in conjunction with our historical consolidated financial statements and accompanying notes thereto included elsewhere in this Form 10-K.

The Energy Transfer Transactions discussed previously were accounted for as a reverse acquisition in accordance with Statement of Financial Accounting Standards No. 141, *Business Combinations* (SFAS 141). Although Heritage was the surviving parent entity for legal purposes, ETC OLP was the acquirer for accounting purposes. As a result, ETC OLP s historical financial statements became our historical financial statements as the registrant. The operations of Heritage prior to the Energy Transfer Transactions are referred to herein as Heritage.

The Energy Transfer Transactions affect the comparability of our financial statements for the year ended August 31, 2005 to the year ended August 31, 2004 because our consolidated financial statements for the year ended August 31, 2004 reflect the results of ETC OLP and its subsidiaries for the full period and the results of HOLP and HHI only from January 20, 2004 through August 31, 2004. The aggregate results in the propane segments disclosed below reflect Heritage s historical results for the year ended August 31, 2004 combined with the historical results of Energy Transfer Company for the year ended August 31, 2004, and are presented for comparability purposes only. This aggregate information (i) is not necessarily indicative of the results of operations that would have occurred had the transactions been made at the beginning of the periods presented or the future results of the combined operations and (ii) is not a measure of performance calculated in accordance with generally accepted accounting principles.

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The comparability of our financial statements is also affected by our purchase of Titan in June 2006, HPL in January 2005 and ET Fuel System in June 2004 and the sale of ETC Oklahoma (EIK City) in April 2005. See Note 2 to our consolidated financial statements for a detailed discussion of our significant acquisitions and dispositions during fiscal years 2006, 2005 and 2004.

Analysis of Operating Data

Volumes of natural gas sales, NGL sales including propane, and natural gas transported by our midstream, transportation and storage, retail propane, and wholesale propane segments are as follows:

Midstream

	Years Ended August 31,		
	2006	2005	2004
Natural gas sales, MMBtu/d	1,552,753	1,578,833	1,026,773
NGL sales, Bbls/d	10,425	12,707	6,920

For the year ended August 31, 2006, natural gas sales volumes decreased by 26,080 MMBtu/d compared to the year ended August 31, 2005. The decrease was principally due to less marketing activity by our producer services operations towards the latter half of fiscal year 2006 and a change in contract mix with one of our major producers where we now charge a fee to gather, process and transport natural gas rather than buying and selling the natural gas on our behalf. Our NGL sales volumes vary due to our ability to by-pass our processing plants when conditions exist that make it less favorable to process and extract NGLs from our processing plants. The decrease in NGL sales volumes is principally due to a change in contract mix as noted above and the election to by-pass our processing plant as a result of less favorable market conditions during the second fiscal quarter of the year ended August 31, 2006.

For the year ended August 31, 2005, natural gas sales volumes were 1,578,833 MMBtu/d compared to 1,026,773 MMBtu/d for the year ended August 31, 2004, an increase of 552,060 MMBtu/d. The increase in natural gas sales volumes was a result of our expanded marketing efforts, enhanced relationships with producers and expanded credit facilities with commodity counter parties. The increase was also attributable to the acquisition of the Texas Chalk and Madison Systems on November 1, 2004, as the Texas Chalk and Madison Systems essentially doubled the number of producing wells from 1,000 to 2,000. NGL sales volumes were 12,707 Bbls/d and 6,920 Bbls/d for the year ended August 31, 2005 and August 31, 2004, respectively. Our NGL sales volumes vary due to our ability to by-pass our processing plants when conditions exist that make it less favorable to process and extract NGLs from our processing plants. The increase in NGLs sales volumes is principally due to the increased natural gas sales volumes processed through our processing plants.

Transportation and Storage

	Years Ended August 31,		
	2006	2005	2004
Natural gas MMBtu/d transported	4,633,069	3,495,434	1,090,710
Natural gas MMBtu/d sold	1,580,638	1,361,729	

For the year ended August 31, 2006, transported natural gas volumes increased by 1,137,635 MMBtu/d. The increase in transportation volumes is principally due to the increased volumes experienced in the Oasis Pipeline system, ET Fuel system and East Texas Pipeline system as a result of our effort to secure firm commitments on our transportation assets and a higher price differential between the Waha and Katy market hubs during the periods presented. Additionally, warmer weather during the 2006 fiscal year resulted in an increase in demand for natural gas. The higher temperatures required more demand for natural gas to be used by electricity-producing power plants connected to our assets. Natural gas sales volumes on the HPL System for the year ended August 31, 2006 increased

218,909 MMBtu/d compared to the year ended August 31, 2005, principally due to increased marketing efforts with our existing and new customers and increased well connects which has increased our supply on the HPL System.

For the year ended August 31, 2005, transportation natural gas volumes increased by 2,404,724 MMBtu/d from 1,090,710 MMBtu/d to 3,495,434 MMBtu/d for the year ended August 31, 2005. The increase in transportation volumes is principally due to the increased volumes experienced on our Oasis Pipeline, the acquisition of the ET Fuel System in June 2004, the completion of the East Texas Pipeline in June 2004, and additional transportation

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volumes from the HPL System acquisition. As noted above, the transportation and storage segment also generates revenue and margin from the sale of natural gas on the HPL System to its customers. The HPL System s natural gas sales volumes were 1,361,729 MMbtu/d for the period from acquisition to August 31, 2005 and it processed 1,735 Bbls/d during the same period.

Propane

	Years Ended August 31,			
	2006	2005	2004	2004 (Aggregate)
Gallons sold (in thousands)				
Retail	429,118	406,334	226,209	397,862
Wholesale	79,348	70,047	35,719	64,399

Retail Propane. The 22.8 million net gallon increase in retail propane gallons sold for the year ended August 31, 2006, compared to the year ended August 31, 2005, includes a 24.5 million gallon increase due to the Titan acquisition for the months of June, July and August 2006, 15.9 million gallons were added through other propane acquisitions, offset by a decrease of 17.6 million gallons related to warm weather and higher propane commodity prices. The weather in our areas of operations during the year ended August 31, 2006 was 3.5% warmer than the year ended August 31, 2005 and 10.6% warmer than normal.

For the year ended August 31, 2005 total retail propane gallons sold were 406.3 million gallons, compared to 226.2 million retail propane gallons reflected in the year ended August 31, 2004. The difference in retail gallons sold is partially due to the fact that the Energy Transfer Transactions described above resulted in reverse acquisition accounting and ETC OLP had no propane operations prior to the Energy Transfer Transactions. As a comparison, we would have reflected an aggregate of 397.9 million retail gallons if the Energy Transfer Transactions would have occurred at the beginning of fiscal year 2004. The increase in fiscal year 2005 over fiscal year 2004 aggregate volumes is due to a 23.0 million gallon increase resulting from volumes sold by customer services locations added through acquisitions, offset by a 14.5 million gallon decline in volumes sold due in part to warmer weather. We experienced temperatures that were 6.9% warmer than normal and 0.7% warmer than the year ended August 31, 2004. We increased our marketing efforts to attain new customers, which partially offsets the negative factors described above.

Wholesale Propane. For the year ended August 31, 2006, sales of wholesale propane gallons increased by 9.3 million gallons compared to the year ended August 31, 2005. Of this increase, 3.5 million is due to an increase in gallons sold in our U.S. wholesale operations as a result of several new customers in our eastern wholesale operations, and an increase of 5.8 million gallons in our Canadian wholesale operations related to increased marketing efforts in our Canadian operations.

For the year ended August 31, 2005 we sold 70.0 million wholesale propane gallons as compared to 35.7 million gallons in the year ended August 31, 2004. As a comparison, we would have reflected aggregate volumes of 64.4 million gallons for the year ended August 31, 2004 if the Energy Transfer Transactions had occurred at the beginning of fiscal year 2004. Of the 5.6 million gallon increase in wholesale propane gallons in fiscal year 2005 over fiscal year 2004 aggregate volumes, 0.8 million is primarily due to customers added from an acquisition in December 2003, 5.4 million gallons is due to an increase in our foreign operations and we experienced a decrease of 0.6 million gallons related to warmer weather.

Analysis of Results of Operations

Fiscal Year Ended August 31, 2006 Compared to Fiscal Year Ended August 31, 2005

Consolidated Results

	Years Ended August 31, 2006	August 31, 2005	Amount of Change
Consolidated Information:			
Revenues	$ 7,859,096	$ 6,168,798	$ 1,690,298
Cost of sales	6,568,316	5,381,515	1,186,801
Gross margin	1,290,780	787,283	503,497
Operating expenses	422,989	319,554	103,435
Selling, general and administrative	107,505	62,735	44,770
Depreciation and amortization	117,415	92,943	24,472
Consolidated operating income	642,871	312,051	330,820
Interest expense	(113,857)	(93,017)	(20,840)
Loss on extinguishment of debt		(9,550)	9,550
Equity in earnings (losses) of affiliates	(479)	(376)	(103)
Gain (loss) on disposal of assets	851	(330)	1,181
Interest and other income, net	14,620	631	13,989
Income tax expense	(25,920)	(7,295)	(18,625)
Minority interests	(2,234)	(731)	(1,503)
Income from continuing operations	515,852	201,383	314,469
Income from discontinued operations, net of income tax expense		147,967	(147,967)
Net income	$ 515,852	$ 349,350	$ 166,502

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See the detailed discussion of revenues, costs of sales, margin and operating expense by operating segment below.

Interest Expense. For the year ended August 31, 2006 compared to the year ended August 31, 2005, interest expense increased $20.8 million. The principal factor for this increase is a net $22.1 million increase in interest expense related to borrowings on the 2005 Senior Notes and the Revolving Credit Facility which we entered into January 2005 to refinance debt at ETC OLP and fund the HPL acquisition, offset principally by an increase in unrealized gains of $1.2 million related to interest rate swaps. See Note 10 - Price Risk Management Assets and Liabilities , included in our consolidated financial statements for further discussion on interest rate hedges.

Loss on Extinguishment of Debt. During the year ended August 31, 2005, we refinanced certain debt and wrote off $9.6 million of debt issuance costs associated with the debt that was repaid with the proceeds from the issuance of $750.0 million of 5.95% senior notes. The write-offs were accounted for as loss on extinguishment of debt.

Interest and Other Income, Net. The increase in interest and other income, net of $14.0 million for the year ended August 31, 2006 compared to the year ended August 31, 2005, is not material. Other income in fiscal year 2006 includes $7.7 million received from the favorable judgment on the SCANA litigation (see Notes 6 and 9 of our consolidated financial statements for further detail).

Income Tax Expense. As a partnership, we are not subject to income taxes. However, certain wholly-owned subsidiaries are corporations that are subject to income taxes. The increased expense of $18.6 million for the year ended August 31, 2006 is attributed principally to higher income due to gains on financial derivative activity recognized by a taxable subsidiary. No similar gains were realized by such subsidiary in prior periods.

Income from Continuing Operations. The increase in income from continuing operations of $314.5 million for the year ended August 31, 2006 compared to the year ended August 31, 2005, is principally due to acquisition-related income, increased volumes and margins on our midstream and transportation and storage assets and favorable price movement on our derivative positions during fiscal year 2006.

Income from Discontinued Operations. On April 14, 2005, we completed the sale of our Oklahoma gathering, treating and processing assets, referred to as the Elk City System. For the year ended August 31, 2005, the income from discontinued operations included the gain on sale of the Elk City System of $142.5 million, net of income taxes, and revenues of $105.5 million offset by costs and expenses of $100.0 million, resulting in income from discontinued operations of $148.0 million.

There were no discontinued operations for the year ended August 31, 2006.

Net Income. Net income increased by $166.5 million between the comparable years of August 31, 2006 and 2005. Excluding the $148.0 million of income from discontinued operations during the year ended August 31, 2005, net income increased by $314.5 million in fiscal year 2006, as compared to fiscal year 2005. The increase is principally due to the effect of the HPL acquisition described above, together with the effects of favorable price movements on financial derivative positions and increased volumes and margins on our midstream and transportation and storage assets.

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Operating Results by Segment

Midstream Segment

	Years Ended August 31, 2006	August 31, 2005	Amount of Change
Revenues	$ 4,223,544	$ 3,246,772	$ 976,772
Cost of sales	4,000,461	3,102,539	897,922
Gross Margin	223,083	144,233	78,850
Operating expenses	31,910	22,835	9,075
Selling, general and administrative	23,922	9,685	14,237
Depreciation and amortization	15,744	12,580	3,164
Segment operating income	$ 151,507	$ 99,133	$ 52,374

Gross Margin. For the year ended August 31, 2006, midstream s gross margin increased by $78.9 million. The increase was principally due to higher margins on gas sales made by our producer services and increased volumes on our gathering systems which resulted in higher fee-based revenues. Additionally, processing margins on our Southeast Texas System increased as a result of favorable processing conditions during the year ended August 31, 2006 compared to last year. The increase was offset by a decrease of $30.5 million in our trading activities principally due to a contingency accrual recorded during the three months ended August 31, 2006.

Operating Expenses. Midstream operating expenses increased $9.1 million and was primarily driven by $3.2 million in increased measurement expenses, $1.1 million in increased chemical costs, $0.7 million in scheduled compressor and pipeline maintenance expense and pipeline integrity costs, $0.9 million in employee costs, and increases of $3.2 million in other operating expenses.

Selling, General and Administrative Expenses. The allocation of departmental costs between the midstream and the transportation and storage segments is based on factors such as headcount, number of meters, and on-going projects and is intended to fairly present the segment s operating results. Midstream selling, general and administrative expenses for the year ended August 31, 2006 increased $14.2 million compared to the year ended August 31, 2005. The increase was attributable to increases of $28.5 million in employee-related costs such as salaries, incentive compensation and healthcare costs, insurance premium increases of $2.2 million, increases in office-related expenses of $4.0 million, $2.7 million in increased legal, audit and consulting fees, and increases in other general and administrative expenses of $2.0 million. The increase was offset by increases of $25.2 million in departmental costs allocated to the transportation and storage operating segment. The increased costs are principally due to the growth caused by the recent acquisitions, internal growth projects and upgraded information systems.

Depreciation and amortization. Midstream depreciation and amortization expense increased $3.2 million for the year ended August 31, 2006 compared to fiscal year 2005 is principally due to the Devon acquisition in November 2004 and pipeline and equipment placed into service subsequent to August 31, 2005.

Transportation and Storage Segment

	Years Ended August 31, 2006	August 31, 2005	Amount of Change
Revenues	$ 5,013,224	$ 2,608,108	$ 2,405,116
Cost of sales	4,322,217	2,280,082	2,042,135

Gross Margin	691,007	328,026	362,981
Operating expenses	171,312	113,166	58,146
Selling, general and administrative	46,520	27,020	19,500
Depreciation and amortization	42,477	27,742	14,735
Segment operating income	$ 430,698	$ 160,098	$ 270,600

Gross Margin. For the year ended August 31, 2006 as compared to fiscal year 2005, transportation and storage gross margin increased by $363.0 million, principally due to the following:

Increased volumes and prices. The increase is principally due to the increase in average natural gas prices period to period which promotes shippers to transport natural gas to more liquid markets such as the Katy Hub and our strategy to pursue additional volumes on our transportation pipeline systems. The price differential

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between the Waha and Katy market hubs increased between the 2005 and 2006 fiscal years, thereby influencing shippers to transport natural gas to regions where natural gas prices are more favorable. We have also successfully secured more firm contracts as evidenced by our recent transportation agreement with XTO (see Note 9 to our consolidated financial statements). In addition, our Fort Worth Basin expansion, completed in May 2005, has also allowed shippers to move more gas from the Barnett Shale. Our margins for the year ended August 31, 2006 were also affected favorably by higher than normal temperatures during the year ended August 31, 2006 in regions where our assets are located. The higher temperatures increased demand for natural gas to be used by electricity-producing power plants connected to these assets. Furthermore, our margin was favorably impacted by an increase in fuel retention fees due to the increase in volumes on our transportation pipelines and an increase in average natural gas prices during the 2006 fiscal year compared to the 2005 fiscal year. Excluding the impact of volumetric changes, our fuel retention fees are directly impacted by changes in natural gas prices. Increases in natural gas prices tend to increase our fuel retention fees and decreases in natural gas prices tend to decrease our fuel retention fees. We expect our gross margins to continue to increase as a result of this expansion and our recently announced expansion projects;

The acquisition of HPL in January 2005. The results for the year ended August 31, 2005 contain seven months of HPL s operating results as compared to twelve months of HPL s operating results included in fiscal year 2006. For the year ended August 31, 2006, HPL s margin was principally affected by the sale of natural gas held in storage during the winter months when demand for natural gas is strong, increased margins resulting from favorable pricing between the west and east markets in the Houston Ship Channel, and gains on derivatives as noted below. The favorable pricing was attributed to the effects of the hurricanes that struck the east Texas and Louisiana coastlines in August and September 2005. However, such margins were at lower levels than previously experienced during the three months ended November 30, 2005. Such pricing continues to remain at or below levels experienced during the three months ended November 30, 2005. Additionally, we sold approximately 16.0 Bcf of natural gas held in our Bammel storage facility during the three months ended August 31, 2006 compared to 10.6 Bcf during the three months ended August 31, 2005; and

Discontinued Hedge Accounting. In January and February 2006, we discontinued application of hedge accounting in connection with certain derivative financial instruments that were qualified for and designated as cash flow hedges related to forecasted sales of natural gas stored in our Bammel storage facilities. The discontinuation resulted from our determination that the originally forecasted sales of natural gas from the storage facilities were no longer probable to occur by the end of the originally specified time period, or within an additional two-month period of time thereafter. The determination was made principally due to the unseasonably warm weather that occurred during January 2006 through March 2006. As a result, during the year ended August 31, 2006, we recognized previously deferred unrealized gains of approximately $84.7 million from the discontinuation of hedge accounting.

Operating Expenses. Transportation and storage operating expenses increased $58.1 million when comparing the year ended August 31, 2006 to fiscal year 2005. The increase was principally attributable to increases of $32.4 million in operating expenses related to the HPL acquisition, $19.5 million related to compressor fuel consumption resulting from higher throughput volumes and increased gas prices during the year ended August 31, 2006, $2.1 million in property taxes, $2.5 million in pipeline maintenance, $1.4 million in compressor rental and maintenance, and $1.3 million in increased employee costs, offset by a decrease of $1.1 million in other operating expenses.

Selling, General and Administrative Expenses. Transportation and storage selling, general and administrative expenses increased $19.5 million for year ended August 31, 2006 compared to the year ended August 31, 2005 principally due to an increase in certain departmental costs allocated from the midstream segment. The increase in allocated departmental costs is due to the increase in employee headcount resulting primarily from the HPL acquisition and an increase in salaries and wages, incentive compensation expense, and other employee-related expenses.

Depreciation and amortization. Transportation and storage depreciation and amortization expense increased $14.7 million for the year ended August 31, 2006 compared to the year ended August 31, 2005. The increase was principally due to the HPL acquisition in January 2005, the Fort Worth Basin expansion project completed in May 2005 and additional compressors and equipment added to existing systems.

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Retail Propane Segment

	Years Ended August 31, 2006	Years Ended August 31, 2005	Amount of Change
Retail propane revenues	$ 799,358	$ 641,071	$ 158,287
Other propane related revenues	80,198	68,402	11,796
Retail propane cost of sales	493,642	384,186	109,456
Other propane related cost of sales	21,776	19,554	2,222
Gross margin	364,138	305,733	58,405
Operating expenses	212,188	176,277	35,911
Selling, general and administrative	17,859	11,067	6,792
Depreciation and amortization	58,036	51,487	6,549
Segment operating income	$ 76,055	$ 66,902	$ 9,153

Revenues. Of the total increase in retail propane revenue of $158.3 million between the years ended August 31, 2006 and 2005, $47.1 million is due to the increase in volumes sold by customer service locations added through the Titan acquisition in June 2006, $29.6 million is due to the increase in volumes sold by customer service locations added through other propane acquisitions and $114.4 million is due to higher selling prices. These increases were offset by a decrease of $32.8 million due to the adverse impact of weather related volumes described above. Other propane related revenues increased $11.8 million for the year ended August 31, 2006 compared to fiscal year 2005 primarily due to other propane related revenues of companies we have acquired between the two years.

Costs of Sales. During the year ended August 31, 2006 compared to the year ended August 31, 2005, retail propane cost of sales increased by $109.5 million of which $30.8 million is a result of an overall increase in gallons sold by customer service locations added through the Titan acquisition, $18.2 million due to an overall increase in gallons sold by customer service locations added through other propane acquisitions and $80.7 million is due to higher cost of fuel, offset by a decrease of $20.2 million due to the impact of weather related volumes described above.

Gross Margin. The overall increase in gross margins for the year ended August 31, 2006 compared to fiscal year 2005 is a function of acquisition-related increases and higher sales prices.

Operating Expenses. During the year ended August 31, 2006, operating expenses increased by $35.9 million compared to last year due to a combination of a $21.4 million increase due to the Titan acquisition, a $9.2 million increase in our employee base from other acquisitions and annual salary increases, $3.4 million due to higher fuel costs to run our vehicles and other vehicle expenses, and a $4.7 million general increase in other operating expenses primarily from other acquisitions, offset by a $2.8 million net decrease in other operating expenses.

Selling, General and Administrative Expenses. The increase in selling, general and administrative expenses for the comparable years of August 31, 2006 and 2005 is primarily due to increases in administrative bonuses, salaries and deferred compensation expense related to increases in staffing and additional restricted unit awards outstanding.

Operating Income. For the year ended August 31, 2006, total operating income increased by $9.2 million compared to the year ended August 31, 2005. This increase is primarily due to the changes in revenues and expenses described above.

Wholesale Propane Segment

	Years Ended August 31,	Years Ended August 31,	Amount of Change

	2006	2005	
Revenues	$ 94,288	$ 68,833	$ 25,455
Cost of sales	87,337	64,667	22,670
Gross margin	6,951	4,166	2,785
Operating expenses	3,031	3,139	(108)
Selling, general and administrative	1,916	1,564	352
Depreciation and amortization	742	754	(12)
Segment operating income (loss)	$ 1,262	$ (1,291)	$ 2,553

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Revenues. Of the increase of $25.5 million in wholesale revenue for the year ended August 31, 2006 compared to fiscal year 2005, $11.3 million is primarily related to the increase in gallons sold to new customers in our eastern wholesale and Canadian operations and $14.2 million is related to higher selling prices.

Costs of Sales. For the year ended August 31, 2006 compared to fiscal year 2005, total cost of sales increased by $22.7 million. Of the increase, $12.4 million is due to higher selling prices and $10.3 million is due to the increase in customers in our eastern wholesale operations described above.

Gross Margin. The overall increase in gross margin for the year ended August 31, 2006 compared to August 31, 2005, is primarily a function of the activities described above in revenues and costs related to the new customers in our eastern wholesale and Canadian operations.

Operating Income (Loss). The increase in operating income of $2.6 million during the year ended August 31, 2006, compared to fiscal year 2005 is primarily due to the changes in revenues and expenses described above.

Other

	Years Ended August 31, 2006	August 31, 2005	Amount of Change
Revenue	$ 7,740	$ 6,867	$ 873
Cost of sales	2,139	1,742	397
Operating expenses	4,548	4,137	411
Depreciation and amortization	416	380	36
Other operating income	$ 637	$ 608	$ 29
Unallocated selling, general and administrative expenses	$ 17,288	$ 13,399	$ 3,889

Unallocated Selling, General and Administrative Expenses. The selling, general and administrative expenses that relate to the general operations of the Partnership are not allocated to our segments.

Unallocated selling, general and administrative expenses increased $3.9 million for the year ended August 31, 2006 compared to the year ended August 31, 2005. This increase is primarily attributed to a $1.0 million increase in executive salaries due to additional staffing, a $0.4 million increase in professional fees due to our on-going efforts related to the Sarbanes-Oxley Act and other Partnership expenses, and a $2.5 million increase in additional executive bonuses and non-cash compensation related to additional staffing and outstanding restricted units awards.

Fiscal Year Ended August 31, 2005 Compared to Fiscal Year Ended August 31, 2004

Consolidated Results

	Year Ended August 31, 2005	August 31, 2004
Revenues	$ 6,168,798	$ 2,346,957
Cost of sales	5,381,515	1,981,424

Gross margin	787,283	365,533
Operating expenses	319,554	147,374
Selling, general and administrative	62,735	30,471
Depreciation and amortization	92,943	48,599
Consolidated operating income	312,051	139,089
Equity in earnings (losses) of affiliates	(376)	363
Interest expense	(93,017)	(41,190)
Loss on extinguishment of debt	(9,550)	
Loss on disposal of assets	(330)	(1,006)
Interest and other income, net	631	509
Minority interests	(731)	(295)
Income tax expense	(7,295)	(4,481)
Income from continuing operations	201,383	92,989
Income from discontinued operations, net of income tax expense	147,967	6,163
Net income	$ 349,350	$ 99,152

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Interest Expense. Interest expense was $93.0 million for the year ended August 31, 2005 as compared to $41.2 million for the year ended August 31, 2004. Of the $51.8 million increase for the year ended August 31, 2005 as compared to the year ended August 31, 2004, $12.7 million is due to the interest of our propane segments for a full year in fiscal year 2005 whereas for the year ended August 31, 2004, prior to the Energy Transfer Transactions propane segment interest expense was not included in expense, $43.5 million is the result of the borrowings on the Senior Notes and the Revolving Credit Facility in January 2005 to finance the HPL acquisition, $1.0 million is related to the amortization of financing costs and the bond discount related to the Senior Notes and the Revolving Credit Facility, offset by a decrease of $1.5 million from gains on interest rate swaps that was included in interest expense during the year ended August 31, 2005 and was not present in 2004, $2.0 million that is attributed to reduced interest in our midstream and transportation and storage segments due to the reduction of long term debt in January 2005 and the effects of interest rate swaps accounted for at ETC OLP, and a $1.9 million decrease in interest expense in our propane segments which is primarily due to the reduction of principal on several of HOLP s Senior Secured Notes from annual payments during the year ended August 31, 2005.

Loss on Extinguishment of Debt. As a result of refinancing certain debt during the year ended August 31, 2005, we wrote off $8.0 million of debt issuance costs associated with the debt that was repaid with the proceeds from the issuance of $750.0 million of Senior Notes. We also wrote off $1.6 million of deferred debt costs during the year ended August 31, 2005 as a result of repaying the debt with ETE that we incurred to purchase the working inventory of natural gas related to the acquisition of the HPL System. The write-off was accounted for as a loss on extinguishment of debt.

Income Tax Expense. Income tax expense was $7.3 million for the year ended August 31, 2005 as compared to $4.5 million for the year ended August 31, 2004. The increase in income tax expense is due to (1) income tax expense recorded in HHI for the entire period in the year ended August 31, 2005 as compared with the year ended August 31, 2004, when tax expense related to HHI was only included in our results of operations after the Energy Transfer Transactions, and (2) increased income from acquisitions, partially offset by lower taxes on the Oasis Pipeline due to lower taxable income for that tax-paying subsidiary.

Income from Continuing Operations. Income from continuing operations for the year ended August 31, 2005 was $201.4 million as compared to income from continuing operations of $93.0 million for the year ended August 31, 2004. The increase from the 2004 periods to the 2005 periods is principally due to acquisition-related income.

Income from Discontinued Operations. On April 14, 2005, we completed the sale of our Oklahoma gathering, treating and processing assets, referred to as the Elk City System, for total cash proceeds of $191.6 million, including certain adjustments as defined in the purchase and sale agreement. Revenues from the Elk City System were $105.5 million for the period from September 1, 2004 to April 14, 2005 as compared to $135.3 million for the year ended August 31, 2004. Costs and expenses of the Elk City System were $100.0 million for the period from September 1, 2004 to April 14, 2005 and $129.1 million for the year ended August 31, 2004. Income from discontinued operations for the period from September 1, 2004 to April 14, 2005 and for the year ended August 31, 2004 was $5.5 million and $6.2 million, respectively. The decrease in revenues, expenses and income was principally due to the sale occurring in April 2005. The gain on the sale of the Elk City System was $142.5 million, net of related income tax expense of $1.8 million.

Net Income. Net income was $349.4 million for the year ended August 31, 2005, as compared to $99.2 million for the year ended August 31, 2004. The increase in net income for the year ended August 31, 2005 compared to August 31, 2004 is largely due to the effect of the Energy Transfer Transactions, acquisition-related income, and the divestiture of the Elk City system.

Operating Results by Segment

Midstream Segment

	Years Ended	
	August 31,	August 31,
	2005	2004
Revenues	$ 3,246,772	$ 1,880,663
Cost of sales	3,102,539	1,787,849

Gross Margin	144,233	92,814
Operating expenses	22,835	12,541
Selling, general and administrative	9,685	10,387
Depreciation and amortization	12,580	9,637
Segment operating income	$ 99,133	$ 60,249

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Gross Margin. Midstream s gross margin increased $51.4 million from $92.8 million for the year ended August 31, 2004 to $144.2 million for the year ended August 31, 2005. The increase is principally due to increases in margin pertaining to increased volumes experienced on our Southeast Texas System and increased marketing efforts by our producer services. In addition, fee-based revenue increased principally due to increased processing, treating and gathering fees resulting from the increased throughput volumes and the acquisition of the Texas Chalk and Madison System in November 2004. The increase in fee based revenue was also due to a change in the contract mix with a major producer during the third quarter of our 2005 fiscal year; however, this change should have no effect on overall midstream margins. The increase in margin during the year ended August 31, 2005 was also due to mark-to-market gains resulting from favorable price movements in relation to our overall derivative positions. The price movements were a result of the effects of Hurricane Katrina during the latter part of August 2005.

Operating Expenses. For the year ended August 31, 2005, Midstream operating expenses increased $10.3 million to $22.8 million from $12.5 million for the year ended August 31, 2004. The increase was principally due to $3.1 million in increased compressor and pipeline maintenance, $1.8 million in increased measurement expenses, $1.8 million in increased property taxes, and $3.6 million, in the aggregate, of other operating expenses such as chemicals, electricity, and other plant operating expenses, primarily due to the Texas Chalk and Madison Systems acquisition and increased throughput experienced on our existing systems.

Selling, General and Administrative Expenses. Midstream selling, general and administrative expenses decreased from $10.4 million for the year ended August 31, 2004 to $9.7 million for the year ended August 31, 2005. The decrease was principally due to $9.5 million in certain departmental costs incurred by the midstream segment and allocated to the transportation and storage operating segment. The decrease was offset by increases of $6.7 million in employee-related expenses such as salary, incentive compensation and health care costs, and $2.1 million in other general and administrative costs such as office, legal, and insurance expense.

Depreciation and Amortization. Midstream depreciation and amortization was $12.6 million for the year ended August 31, 2005 compared to $9.6 million for the year ended August 31, 2004, an increase of $3.0 million. The increase was principally due to the Texas Chalk and Madison Systems acquisition in November 2004.

Transportation and Storage Segment

	Years Ended	
	August 31,	**August 31,**
	2005	**2004**
Revenues	$ 2,608,108	$ 113,938
Cost of sales	2,280,082	11,270
Gross Margin	328,026	102,668
Operating expenses	113,166	30,571
Selling, general and administrative	27,020	8,372
Depreciation and amortization	27,742	7,426
Segment operating income	$ 160,098	$ 56,299

Gross Margin. Transportation and storage gross margin was $328.0 million for the year ended August 31, 2005 as compared to $102.7 million for the year ended August 31, 2004, an increase of $225.3 million. The increase in transportation and storage gross margin is principally due to the following:

Increased volumes on our Oasis Pipeline. The increase is principally due to the increase in average natural gas prices period to period which promotes shippers to transport natural gas to more liquid markets such as the Katy Hub and our strategy to pursue additional volumes in the middle and west end of the Oasis Pipeline System. Additionally, the average differential between the Waha market hub and Katy market hub increased $0.051 from $0.249 for the year ended August 31, 2004 to $0.30 for the year ended August 31, 2005, thereby influencing shippers to transport natural gas to regions where natural gas prices are more favorable.

ET Fuel System acquisition in June 2004. In connection with the acquisition of the ET Fuel System in June of 2004, we entered into an eight-year transportation agreement with TXU Portfolio Management Company, LP

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(TXU Shipper) to transport a minimum of 115.6 billion Btu per year. We also entered into two eight-year natural gas storage agreements with TXU Shipper to store gas at two natural gas storage facilities that are part of the ET Fuel System. During the third fiscal quarter of 2005, we were entitled to receive additional fees for the difference between the actual volumes transported by TXU Shipper on the ET Fuel System and the minimum amount as stated above. As a result, we recognized an additional $14.7 million in fees during the third fiscal quarter of 2005. The increase in margin was also due to the Fort Worth Basin expansion completed in May 2005.

East Texas System. We completed the East Texas System in June 2004.

HPL System acquired in January 2005. As discussed above, we expect significant fluctuations in our margins from period to period on the HPL System due to the timing of injections and withdrawals of working natural gas.

Operating Expenses. For the year ended August 31, 2005, transportation and storage operating expenses were $113.2 million as compared to $30.6 million for the year ended August 31, 2004, an increase of $82.6 million. The increase was principally attributable to the ET Fuel System acquisition in June 2004, the completion of the East Texas Pipeline in June 2004 and the acquisition of HPL in January 2005. In addition, Oasis Pipeline s operating expenses increased $9.1 million as a result of increased gas consumption required to transport natural gas through the pipeline and increases in other operating expenses such as compressor and pipeline maintenance and ad valorem taxes.

Selling, General and Administrative Expenses. Transportation and storage selling, general and administrative expenses increased $18.6 million to $27.0 million for the year ended August 31, 2005 from $8.4 million for the year ended August 31, 2004. The increase was principally due to $9.0 million in general and administrative expenses related to the HPL acquisition, $1.4 million in general and administrative expenses relating to the ET Fuel acquisition, and $9.5 million related to certain department costs allocated from the midstream segment.

Depreciation and Amortization. For the year ended August 31, 2005 transportation and storage depreciation and amortization increased $20.3 million from $7.4 million for the year ended August 31, 2004 to $27.7 million for the year ended August 31, 2005. The increase was principally attributable to the acquisitions of the ET Fuel System and HPL System during the 2005 fiscal period and the completion of the East Texas Pipeline in June 2004.

Retail Propane Segment

		Years Ended	
	August 31,	**August 31,**	**August 31,**
	2005 (Actual)	**2004 (Actual)**	**2004 (Aggregate)**
Retail propane revenues	$ 641,071	$ 315,177	$ 536,636
Other propane related revenues	68,402	34,167	60,646
Retail propane cost of sales	384,186	174,769	296,206
Other propane related cost of sales	19,554	9,602	17,512
Operating expenses	176,277	100,093	158,471
Selling, general and administrative	11,067	6,746	11,080
Depreciation and amortization	51,487	30,925	45,979
Segment operating income	$ 66,902	$ 27,209	$ 68,034

Revenues. For the year ended August 31, 2005, we had retail propane revenues of $641.1 million as compared to retail propane revenues of $315.2 million for the year ended August 31, 2004, due in part to the fact that the Energy Transfer Transactions described above resulted in reverse acquisition accounting, and ETC OLP had no propane operations. As a comparison, for the year ended August 31, 2004, aggregate retail propane revenues would have been $536.6 million. Of the $104.5 million aggregate increase, $36.3 million is due to the increase in volumes sold by customer service locations added through acquisitions, $91.1 million is due to higher selling prices which were a result of higher fuel costs that we have passed to our consumer base; offset by a decrease of $22.9 million due to the adverse impact weather had on volumes, as described above. We had other propane related revenues of $68.4 million for the year ended August 31, 2005 compared to $34.2 for the year ended August 31, 2004. As a comparison, aggregate other propane related revenues would have been $60.6 million for the year ended August 31, 2004. The aggregate increase of $7.8 million for the year ended August 31, 2005 compared to the year ended August 31, 2004 is primarily due to other propane revenue from companies acquired during the year ended August 31, 2005 and higher cost of propane related resale items which we have recovered through an increase of our selling prices.

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Costs of Sales. For the year ended August 31, 2005, we had retail propane cost of sales of $384.2 million compared to retail propane cost of sales of $174.8 million for the year ended August 31, 2004. As a comparison, for the year ended August 31, 2004, aggregate retail propane cost of sales would have been $296.2 million. Of the $88.0 million aggregate increase for the year ended August 31, 2005 as compared to the year ended August 31, 2004, $80.0 million reflects the increase due to higher cost of fuel, and $8.0 million is due to the increase in volumes described above. We had other propane related cost of sales of $19.5 million for the year ended August 31, 2005 as compared to $9.6 million for the year ended August 31, 2004. As a comparison, we had aggregate other propane related cost of sales of $17.5 million. The aggregate increase for the year ended August 31, 2005 as compared to the year ended August 31, 2004 is primarily due to acquisition related cost of sales for the year ended August 31, 2005 and higher cost of resale items.

Operating Expenses. For the year ended August 31, 2005, operating expenses for the retail propane segment were $176.3 million and $100.1 million for the year ended August 31, 2004. As a comparison, aggregate retail propane operating expenses would have been $158.5 million for the year ended August 31, 2004, or an aggregate increase of $17.8 million. Of this aggregate increase, approximately $8.7 million related to an increase in our employee base from acquisitions, $3.1 million is due to higher fuel costs to run our vehicles and other vehicle expenses, net business insurance increased $3.1 million, and a remaining increase of $2.9 million due to a general increase in other operating expenses from acquisitions.

Selling, General and Administrative Expenses. For the year ended August 31, 2005, selling, general and administrative expenses for our retail propane segment were essentially equal to aggregate retail propane selling, general and administrative expenses of $11.1 million for the year ended August 31, 2004.

Depreciation and Amortization. For the year ended August 31, 2005, depreciation and amortization in our retail propane segment was $51.5 million as compared $30.9 million for the year ended August 31, 2004. We would have had aggregate depreciation and amortization of $46.0 million for the year ended August 31, 2004. The aggregate increase of $5.5 million is due primarily to the increase in depreciation of assets and amortization of intangible assets added through acquisitions and the additional depreciation and amortization of the assets stepped up to fair market value as a result of the Energy Transfer Transactions.

Operating Income. For the year ended August 31, 2005, we had retail propane operating income of $66.9 million as compared to retail propane operating income of $27.2 million for the year ended August 31, 2004. Aggregate total operating income for the year ended August 31, 2004 was $68.0 million. These variances are primarily due to changes in revenues and expenses described above.

Wholesale Propane Segment

		Years Ended	
	August 31,	**August 31,**	**August 31,**
	2005 (Actual)	**2004 (Actual)**	**2004 (Aggregate)**
Revenues	$ 68,833	$ 27,345	$ 47,941
Cost of sales	64,667	24,871	43,410
Operating expenses	3,139	1,936	2,912
Selling, general and administrative	1,564	918	1,443
Depreciation and amortization	754	432	626
Segment operating loss	$ (1,291)	$ (812)	$ (450)

Revenues. For the year ended August 31, 2005, wholesale propane revenues were $68.8 million, compared to $27.3 million for the year ended August 31, 2004. Aggregate wholesale propane revenues were $47.9 million for the year ended August 31, 2004. Of the aggregate increase of $20.9 million, $0.9 million is due to the increase in gallons due to acquisitions, $15.5 million is related to higher selling prices, and $5.1 million is due to increased marketing efforts in our foreign operations, offset by the decrease of $0.6 million due to weather related gallons described above.

Costs of Sales. For the year ended August 31, 2005, wholesale propane cost of sales was $64.7 million and $24.9 million for the year ended August 31, 2004. As a comparison, aggregate wholesale propane cost of sales would have been $43.4 million for the year ended August 31, 2004. The aggregate increase of $21.3 million is due to a $17.1 million increase from higher selling prices, and a $4.8 increase due to the increase in volumes in our foreign market described above, offset by a $0.6 million decrease due to weather related volumes described above.

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Operating Expenses. For the year ended August 31, 2005, operating expenses for our wholesale propane segment were $3.1 million and $1.9 million for the year ended August 31, 2004, and aggregate wholesale propane operating expenses of $2.9 million for the year ended August 31, 2004, or no significant variance.

Selling, General and Administrative Expenses. Selling, general and administrative expenses for our wholesale propane segment were $1.6 million for the year ended August 31, 2005, compared to wholesale selling, general, and administrative expenses of $0.9 for the year ended August 31, 2004. As a comparison, we had aggregate wholesale selling, general, and administrative expenses of $1.4 million for the year ended August 31, 2004, or no significant variation.

Operating Loss. For the year ended August 31, 2005, we had a domestic wholesale propane operating loss of $1.3 million as compared to operating loss of $0.8 million for the year ended August 31, 2004. Aggregate total operating loss for the year ended August 31, 2004 would have been $0.4 million. The variances are due to the factors described above.

Other

		Years Ended	
	August 31,	August 31,	August 31,
	2005 (Actual)	2004 (Actual)	2004 (Aggregate)
Revenue	$ 6,867	$ 3,465	$ 5,283
Cost of sales	1,742	861	1,304
Operating expenses	4,137	2,234	3,614
Depreciation and amortization	380	179	321
Other operating income	$ 608	$ 191	$ 44
Unallocated selling, general and administrative expenses	$ 13,399	$ 4,047	$ 9,288

Unallocated Selling, General and Administrative Expenses. The selling, general and administrative expenses that relate to the general operations of the Partnership are not allocated to our segments.

For the year ended August 31, 2005, the total unallocated selling, general, and administrative expenses were $13.4 million as compared to $4.0 million unallocated selling, general, and administrative expense for the year ended August 31, 2004. Aggregate total unallocated selling, general, and administrative expense for the year ended August 31, 2004 would have been $9.3 million. The aggregate increase of $4.1 million in unallocated selling, general, and administrative expenses is primarily related to the $4.4 million expense related to our ongoing efforts to comply with the Sarbanes Oxley Act and additional executive wages charged to unallocated selling, general and administrative expenses during fiscal year 2005, offset by approximately $4.5 million of transaction costs related to the Energy Transfer Transactions.

Income Taxes

As a Partnership we generally are not subject to income tax. We are, however, subject to a statutory requirement that our non-qualifying income (including income such as derivative gains from trading activities, service income, tank rentals and others) cannot exceed 10% of our total gross income, determined on a calendar year basis under the applicable income tax provisions. If the amount of our non-qualifying income exceeds this statutory limit, we would be taxed as a corporation. Accordingly, certain activities that generate non-qualified income are conducted through taxable corporate subsidiaries (C corporations). These C corporations are subject to federal and state income tax and pay the income taxes related to the results of their operations. For the years ended August 31, 2006, 2005 and 2004, our non-qualifying income was not expected to, or did not, exceed the statutory limit.

The difference between the statutory rate and the effective rate is summarized as follows:

	Year Ended August 31,		
	2006	2005	2004
Federal statutory tax rate	35.00%	35.00%	35.00%
State income tax rate net of federal benefit	3.10%	3.56%	3.96%
Earnings not subject to tax at the Partnership level	(33.30%)	(36.01%)	(34.64%)
Effective tax rate	4.80%	2.55%	4.32%

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Income tax expense consists of the following current and deferred amounts:

	Year Ended August 31,		
	2006	2005	2004
Current income tax expense:			
Federal	$ 27,640	$ 5,043	$ 6,505
State	1,994	963	830
Deferred income tax expense (benefit):			
Federal	(3,329)	882	(2,677)
State	(385)	407	(177)
Total income tax expense before gain on discontinued operations	25,920	7,295	4,481
Gain on discontinued operations:			
Current income tax expense:			
Federal		1,570	
State		259	
		1,829	
Total income tax expense	$ 25,920	$ 9,124	$ 4,481

We do not expect our tax payments in any year to differ significantly from our current tax provisions.

On May 18, 2006, the Governor of Texas signed into law House Bill 3 (HB-3) which modifies the existing franchise tax law. The modified franchise tax will be computed by subtracting either costs of goods sold or compensation expense, as defined in HB-3, from gross revenue to arrive at a gross margin. The resulting gross margin will be taxed at a one percent tax rate. HB-3 has also expanded the definition of tax paying entities to include limited partnerships such as ours. HB-3 becomes effective for activities occurring on or after January 1, 2007. Based on our initial analysis, we do not believe HB-3 will have a significant adverse impact on our financial position or operating cash flows.

Liquidity and Capital Resources

Our ability to satisfy our obligations and pay distributions to our partners will depend on our future performance, which will be subject to prevailing economic, financial, business and weather conditions, and other factors, many of which are beyond management s control.

Future capital requirements of our business will generally consist of:

- maintenance capital expenditures, which include capital expenditures made to connect additional wells to our natural gas systems in order to maintain or increase throughput on existing assets for which we expect to expend $38.3 million in the next fiscal year and capital expenditures to extend the useful lives of our propane assets in order to sustain our operations, including vehicle replacements on our propane vehicle fleet for which we expect to expend $22.7 million in the next fiscal year;

- growth capital expenditures, mainly for constructing new pipelines, processing plants and treating plants for which we expect to expend $988.6 million in the next fiscal year; and customer propane tanks for which we expect to expend $25.5 million in the next fiscal year; and

- acquisition capital expenditures including acquisition of new pipeline systems and propane operations.

We believe that cash generated from the operations of our businesses will be sufficient to meet anticipated maintenance capital expenditures. We will initially finance all capital requirements by cash flows from operating activities. To the extent that our future capital requirements exceed cash flows from operating activities:

- maintenance capital expenditures will be financed by the proceeds of borrowings under the existing credit facilities described below, which will be repaid by subsequent seasonal reductions in inventory and accounts receivable;

- growth capital expenditures will be financed by the proceeds of borrowings under the existing credit facilities and the issuance of additional Common Units or a combination thereof; and

- acquisition capital expenditures will be financed by the proceeds of borrowings under the existing credit facilities, other lines of credit, long-term debt, the issuance of additional Common Units or a combination thereof.

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The assets utilized in our propane operations do not typically require lengthy manufacturing process time or complicated, high technology components. Accordingly, we do not have any significant financial commitments for maintenance capital expenditures in our propane business. In addition, we do not experience any significant increases attributable to inflation in the cost of these assets or in our propane operations. The assets used in our midstream and transportation and storage segments, including pipelines, gathering systems and related facilities, are generally long-lived assets and do not require significant maintenance capital expenditures other than those expenditures necessary to maintain the service capacity of our existing assets.

In connection with the HPL acquisition, we engage in natural gas storage transactions in which we seek to find and profit from pricing differences that occur over time. Natural gas is typically purchased and held in storage during the summer months and sold during the winter months. Although we intend to fund natural gas purchases with cash generated from operations, from time to time we may need to finance the purchase of natural gas to be held in storage with borrowings from our current credit facilities. We intend to repay these borrowings with cash generated from operations when the gas is sold.

On October 3, 2006, we announced that we entered into a long-term agreement with CenterPoint Energy Resources Corp (CenterPoint) to provide the natural gas utility with firm transportation and storage services on our HPL System located along the Texas gulf coast region. Under the terms of this agreement. CenterPoint has contracted for 129 Bcf per year of firm transportation capacity combined with 10 Bcf of working gas storage capacity in our Bammel Storage facility. Under the new agreement with CenterPoint, we will no longer need to utilize predominately all of the Bammel Storage facility s working gas capacity for supplying CenterPoint s winter needs. This will reduce our working capital requirements that were necessary to finance the working gas while in storage and will provide us an opportunity to offer storage to third parties. This agreement goes into effect beginning April 1, 2007.

Our internally generated cash flows may change in the future due to a number of factors, some of which we cannot control. These include regulatory changes, the price for our products and services, the demand for such products and services, margin requirements resulting from significant changes in commodity prices, operational risks, the successful integration of our acquisitions, including the recently acquired Titan operations, and other factors.

Operating Activities. Cash provided by operating activities during the year ended August 31, 2006, was $543.9 million as compared to cash provided by operating activities of $169.4 million for the year ended August 31, 2005. The net cash provided by operations for the year ended August 31, 2006 consisted of net income of $515.8 million, non-cash charges of $126.2 million, principally depreciation and amortization, unit based compensation expense, and deferred taxes, and operating funds used of $98.1 million which decreased components of working capital. Various components of working capital changed significantly from the prior period due to factors such as the variance in the timing of accounts receivable collections, payments on accounts payable, and the timing of the purchase and sale of inventories related to the propane and transportation and storage operations. Accounts receivable and accounts payable both decreased during the year ended August 31, 2006 due primarily to decreases in the volumes and prices in the midstream segment. Customer deposits decreased significantly during the year ended August 31, 2006 due to the delivery of natural gas in 2006 that was prepaid as of August 2005. Accrued liabilities increased significantly during the year ended August 31, 2006, due to certain provisions for environmental, legal and other contingencies.

Investing Activities. Cash used in investing activities during the year ended August 31, 2006 of $1.2 billion is comprised primarily of cash paid for acquisitions of $586.2 million, $680.2 million invested for maintenance and growth capital expenditures needed to sustain operations at current levels and to support growth of operations and $4.6 million for advances and investments in affiliates. Cash used in investing activities was offset by proceeds from the sale of idle property of $6.9 million and cash received for a working capital settlement on the HPL acquisition of $19.6 million. The cash paid for acquisitions included primarily $16.6 million paid for the acquisition of the 2% remaining interests in the HPL System, cash paid for the Titan acquisition of $548.5 million, and other retail propane acquisitions of $20.6 million. In addition to cash paid for acquisitions, we also issued $4.0 million of Common Units in connection with a specific propane acquisition.

Financing Activities. Cash provided by financing activities during the year ended August 31, 2006 was $701.6 million primarily due to the net increase of $912.3 million in debt financing which we used to fund capital expenditures. The debt increase primarily consisted of the advances on the Revolving Credit Facility, offset by debt reduction from unit issuances and other scheduled debt payments in the normal course of business. The debt reduction was primarily funded through the sale of 1,069,850 Limited Partner Units and 2,570,150 Class F Units to ETE for which we received net proceeds of $132.4 million. Our General Partner contributed $2.8 million in connection with the sale of Limited Partner Units in order to maintain its 2% ownership in us during the year ended

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August 31, 2006. We paid $343.8 million in distributions to our Common Unitholders during the year ended August 31, 2006. We also paid other financing costs of $2.0 million during the year ended August 31, 2006.

Financing and Sources of Liquidity

On August 9, 2006 we filed a Registration Statement on Form S-3 with the Securities and Exchange Commission to register for future sale up to $1.5 billion aggregate offering price of a combination of our limited partner interests and debt securities and guarantees of such debt securities by certain of our subsidiaries. On October 23, 2006, we closed the issuance, under our $1.5 billion S-3 registration statement, of $400 million of 6.125% senior notes due 2017 and $400 million of 6.625% senior notes due 2036, and received net proceeds of approximately $791 million. We used the proceeds to pay borrowings and accrued interest under our Revolving Credit Facility. Interest on the 2017 senior notes is payable semiannually on February 15 and August 15 of each year, beginning February 15, 2007, and interest on the 2036 senior notes is payable semiannually on April 15 and October 15 of each year, beginning April 15, 2007. The notes are unsecured senior obligations and will be fully and unconditionally guaranteed by ETC OLP and Titan and all of their direct and indirect wholly-owned subsidiaries.

On April 10, 2006, we filed a Registration Statement on Form S-3 with the Securities and Exchange Commission to register a $1 billion aggregate offering price of Common Units representing our Limited Partner interests. Through August 31, 2006, we have not made any sales under this Registration Statement.

On November 23, 2005 we filed a registered exchange offer to exchange newly issued 5.65% Senior Notes due 2012 (the 2012 Notes) that were registered under the Securities Act of 1933 (the New Notes), for a like amount of outstanding 5.65% Senior Notes due 2012, which had not been registered under the Securities Act (the Old Notes). On February 23, 2006 we commenced the exchange offer which closed on March 31, 2006. All $400.0 million of the Old Notes were tendered pursuant to the exchange offer and were replaced with a like amount of New Notes. The sole purpose of the exchange offer was to fulfill our obligations under the registration rights agreement entered into in connection with our sale of the Old Notes on July 29, 2005. The New Notes issued pursuant to the exchange offer have substantially identical terms to the Old Notes.

Description of Indebtedness

Our indebtedness as of August 31, 2006 consists of $750.0 million in principal amount of 5.95% Senior Notes due 2015, $400.0 million in principal amount of 5.65% Senior Notes due 2012, a Revolving Credit Facility that allows for borrowings of up to $1.3 billion, expanded to $1.5 billion subsequent to August 31, 2006, available through June 29, 2011, and a $200.0 million Revolving Credit Facility that matures on December 1, 2006 (paid and canceled subsequent to August 31, 2006). We also currently maintain separate credit facilities for HOLP. The terms of our indebtedness and our Operating Partnerships are described in more detail below. Failure to comply with the various restrictive and affirmative covenants of the credit agreements could negatively impact our ability and the ability of our subsidiaries to incur additional debt and our ability to pay our distributions. We are required to measure these financial tests and covenants quarterly and, as of August 31, 2006, we were in compliance with all financial requirements, tests, limitations, and covenants related to financial ratios under our existing credit agreements.

2005 Senior Notes

ETC OLP and all of its direct and indirect wholly-owned subsidiaries act as the guarantor of the debt obligations for the 2015 Unregistered Notes issued on January 18, 2005 and the 2012 Notes issued on March 31, 2006. If we were to default, ETC OLP and the other guarantors would be responsible for full repayment of those obligations. The ETP Senior Notes have equal rights to holders of our other current and future unsecured debt.

The Senior Notes represent our senior unsecured obligations and rank equally with all of our other existing and future unsecured and unsubordinated indebtedness. The Senior Notes are jointly and severally guaranteed by ETC OLP and all of the direct and indirect wholly and majority-owned subsidiaries of ETC OLP. The subsidiary guarantees rank equally in right of payment with all of the existing and future unsubordinated indebtedness of our guarantor subsidiaries. The Senior Notes and each guarantee will effectively rank junior to any future indebtedness of ours or our subsidiary guarantors that is both secured and unsubordinated to the extent of the value of the assets securing such indebtedness, and the Senior Notes will effectively rank junior to all indebtedness and other liabilities of our existing and future subsidiaries that are not subsidiary guarantors.

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The Senior Notes were issued under an indenture containing covenants, which include covenants that restrict our ability to, subject to certain exceptions, incur debt secured by liens, engage in sale and leaseback transactions or merge or consolidate with another entity or sell substantially all of our assets.

HOLP Senior Secured Notes

All receivables, contracts, equipment, inventory, general intangibles, cash concentration accounts, and the capital stock of HOLP and its subsidiaries secure the HOLP Senior Secured, Medium Term, and Senior Secured Promissory Notes. In addition to the stated interest rate for the Notes, we are required to pay an additional 1% per annum on the outstanding balance of the Notes at such time as the Notes are not rated investment grade status or higher. As of August 31, 2006 the Notes were rated investment grade or better thereby alleviating the requirement that we pay the additional 1% interest.

Revolving Credit Facilities

ETP Facilities

On December 13, 2005, we entered into the $900.0 million ETP Revolving Credit Facility which replaced the existing Revolving Credit Facility. The ETP Revolving Credit Facility was amended on June 29, 2006 (the Amended and Restated Credit Agreement) allowing for borrowings up to $1.3 billion, expandable to $1.5 billion. The Amended and Restated Credit Agreement is available through June 29, 2011 unless we elect the two successive options (subject to bank approval) to extend the maturity date for a period of 364 days each. Amounts borrowed under the Amended and Restated Revolving Credit Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The Amended and Restated Credit Agreement has a Swingline loan option with a maximum borrowing of $75.0 million at a daily rate based on LIBOR. The commitment fee payable on the unused portion of the facility varies based on our credit rating and the maximum fee is 0.175%. As of August 31, 2006, there was a balance of $1.2 billion in revolving credit loans (including $17.6 million in Swingline loans) and $14.4 million in letters of credit. The weighted average interest rate on the total amount outstanding at August 31, 2006, was 6.04%. The total amount available under the Amended and Restated Revolving Credit Agreement, as of August 31, 2006, which is reduced by any amounts outstanding under the Swingline loan and letters of credit, was $123.0 million. The Amended and Restated Revolving Credit Facility is fully and unconditionally guaranteed by ETC OLP and all of the direct and indirect wholly-owned subsidiaries of ETC OLP and Titan and its wholly-owned subsidiaries. The ETP Revolving Credit Facility is unsecured and has equal rights to holders of our other current and future unsecured debt. On September 25, 2006 we exercised the accordion feature and expanded the total amount of the facility to $1.5 billion.

Prior to December 13, 2005, we had available a $800.0 million Revolving Credit Facility which bore interest at a rate based on either a Eurodollar rate, or a prime rate. The Revolving Credit Facility offered a Swingline loan option with the maximum borrowing of $30.0 million at a daily rate based on the London market. The weighted average interest rate was 4.827% at August 31, 2005. We borrowed $475.0 million under the Revolving Credit Facility to fund a portion of the HPL acquisition in January 2005. As of August 31, 2005, $201.0 million was outstanding under the Revolving Credit Facility which included $15.0 million under the Swingline option and also had outstanding Letters of Credit of $11.3 million. Per the previous agreement, Letter of Credit Exposure plus the Revolving Credit Facility could not exceed the $800.0 million maximum Revolving Credit Facility. Total amount available under the Credit Agreement at August 31, 2005 was $587.7 million.

On May 31, 2006, we entered into a $250.0 million Revolving Credit Facility, which matures under its terms on December 1, 2006. Amounts borrowed under this facility bear interest at a rate based on either a Eurodollar rate or a base rate. The proceeds are intended to be used for working capital purposes. The maximum commitment fee payable on the unused portion of the facility is 0.25%. The $250.0 million Revolving Credit Facility is fully and unconditionally guaranteed by ETC OLP and all of the direct and indirect wholly-owned subsidiaries of ETC OLP. The $250.0 million Revolving Credit Facility is unsecured and has equal rights to holders of our other current and future unsecured debt. On July 3, 2006, we reduced our borrowing capacity on the Revolving Credit Facility to $200.0 million. All terms and maturity date, as mentioned above, remain unchanged. There was $20.0 million outstanding on this facility as of August 31, 2006. The weighted average interest rate on the total amount outstanding at August 31, 2006 was 5.988%. This facility was paid and retired on October 18, 2006.

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HOLP Facilities

Effective August 31, 2006, HOLP entered into the Fourth Amended and Restated Credit Agreement. The terms of the Agreement are as follows:

A $75.0 million Senior Revolving Facility is available through June 30, 2011. The revolving facility may be expanded to $150.0 million. The Facility has a swingline loan option with a maximum borrowing of $10.0 million at a prime rate. Amounts borrowed under this Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The weighted average interest rate was 6.955% for the amount outstanding at August 31, 2006. The commitment fee payable on the unused portion of the facility varies based on the Leverage Ratio, as defined, with a maximum fee of 0.50%. The sum of the loans, swingline loans and letters of credit may not exceed the maximum amount of revolving credit. The agreement includes provisions that may require contingent prepayments in the event of dispositions, loss of assets, merger or change of control. All receivables, contracts, equipment, inventory, general intangibles, cash concentration accounts of HOLP, and the capital stock of HOLP s subsidiaries secure the Facility. As of August 31, 2006, the Facility had a balance outstanding of $20.0 million. A Letter of Credit issuance is available to HOLP for up to 30 days prior to the maturity date of the Senior Revolving Credit Facility. There were outstanding Letters of Credit of $1.0 million at August 31, 2006. The sum of the loans made under the Facility plus the Letter of Credit Exposure and the aggregate amount of all swingline loans cannot exceed the $75.0 maximum amount of the Senior Revolving Facility.

Prior to August 31, 2006, HOLP also maintained a $75.0 million Senior Revolving Acquisition Facility for acquisition of propane-related businesses. Amounts borrowed under the Acquisition Credit Facility bore interest at a rate based on either a Eurodollar rate or a prime rate. All receivables, contracts, equipment, inventory, general intangibles, cash concentration accounts of HOLP, and the capital stock of HOLP s subsidiaries secured the Senior Revolving Acquisition Facility. During the second quarter of fiscal year 2006, HOLP paid in full the outstanding indebtedness under this facility and cancelled the Senior Revolving Acquisition Facility.

Covenants Related to Our Credit Agreements. The agreements for each of the Senior Notes, Senior Secured Notes, Medium Term Note Program, Senior Secured Promissory Notes, and the revolving credit facilities contain customary restrictive covenants applicable to ETP and the Operating Partnerships, including the achievement of various financial and leverage covenants, limitations on substantial disposition of assets, changes in ownership, the level of additional indebtedness and creation of liens. The most restrictive of these covenants require us to maintain ratios of Adjusted Consolidated Funded Indebtedness to Adjusted Consolidated EBITDA (as these terms are similarly defined in the bank credit facilities and the Note Agreements) of not more than 4.75 to 1 and Consolidated EBITDA to Consolidated Interest Expense (as these terms are similarly defined in the bank credit facilities and the Note Agreements) of not less than 2.25 to 1. The Consolidated EBITDA used to determine these ratios is calculated in accordance with these debt agreements. For purposes of calculating the ratios under the bank credit facilities and the Note Agreements, Consolidated EBITDA is based upon our EBITDA, as adjusted for the most recent four quarterly periods, and modified to give pro forma effect for acquisitions and divestures made during the test period and is compared to Consolidated Funded Indebtedness as of the test date and the Consolidated Interest Expense for the most recent twelve months. These debt agreements also provide that the Operating Partnerships may declare, make, or incur a liability to make, restricted payments during each fiscal quarter, if: (a) the amount of such restricted payment, together with all other restricted payments during such quarter, do not exceed Available Cash with respect to the immediately preceding quarter; (b) no default or event of default exists before such restricted payments; and (c) each Operating Partnership s restricted payment is not greater than the product of each Operating Partnership s Percentage of Aggregate Available Cash multiplied by the Aggregate Partner Obligations (as these terms are similarly defined in the bank credit facilities and the Note Agreements). The HOLP debt agreements further provide that HOLP s Available Cash is required to reflect a reserve equal to 50% of the interest to be paid on the notes and in addition, in the third, second and first quarters preceding a quarter in which a scheduled principal payment is to be made on the notes, and a reserve equal to 25%, 50%, and 75%, respectively, of the principal amount to be repaid on such payment dates.

Failure to comply with the various restrictive and affirmative covenants of our bank credit facilities and the Note Agreements could require us to pay debt balances prior to scheduled maturity and could negatively impact the Operating Partnerships ability to incur additional debt and/or our ability to pay distributions. We are required to measure these financial tests and covenants quarterly and were in compliance with all requirements, tests, limitations, and covenants related to the Partnership s and HOLP s debt agreements as of August 31, 2006.

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Contractual Obligations

The following table summarizes our long-term debt and other contractual obligations as of August 31, 2006:

In thousands

		Payments Due by Period			
		Less Than			More Than
Contractual Obligations	**Total**	**1 Year**	**1 3 Years**	**3 5 Years**	**5 Years**
Long-term debt	$ 2,629,702	$ 40,578	$ 90,862	$ 1,256,764	$ 1,241,498
Interest on fixed rate long-term debt (a)	614,499	90,145	170,029	155,581	198,744
Payments on derivatives	38,646	36,918	1,728		
Purchase commitments (b)	482,300	482,300			
Operating lease obligations	49,178	8,809	16,946	13,789	9,634
Totals	$ 3,814,325	$ 658,750	$ 279,565	$ 1,426,134	$ 1,449,876

(a) Fixed rate interest on long-term debt includes the amount of interest due on our fixed rate long-term debt. These amounts do not include interest on our variable rate debt obligations which include our Revolving Credit Facilities and, Revolving Credit Facility Swingline Loan options. As of August 31, 2006, variable rate interest on our outstanding balance of variable rate debt of $1.2 billion would be $72.5 million on an annual basis. See Note 5 Debt Obligations to the consolidated financial statements beginning in Item 8 of this report for further discussion of the long-term debt classifications and the maturity dates and interest rates related to long-term debt.

(b) We define a purchase commitment as an agreement to purchase goods or services that is enforceable and legally binding (unconditional) on us that specifies all significant terms, including: fixed or minimum quantities to be purchased; fixed, minimum or variable price provisions; and the approximate timing of the transactions. We have long and short-term product purchase obligations for propane and energy commodities with third-party suppliers. These purchase obligations are entered into at either variable or fixed prices. The purchase prices that we are obligated to pay under variable price contracts approximate market prices at the time we take delivery of the volumes. Our estimated future variable price contract payment obligations are based on the August 31, 2006 market price of the applicable commodity applied to future volume commitments. Actual future payment obligations may vary depending on market prices at the time of delivery. The purchase prices that we are obligated to pay under fixed price contracts are established at the inception of the contract. Our estimated future fixed price contract payment obligations are based on the contracted fixed price under each commodity contract. Obligations shown in the table represent estimated payment obligations under these contracts for the periods indicated.

Cash Distributions

We will use our cash provided by operating and financing activities from the Operating Partnerships to provide distributions to our Unitholders. Under the Partnership Agreement, we will distribute to our partners within 45 days after the end of each fiscal quarter, an amount equal to all of our Available Cash for such quarter. Available Cash generally means, with respect to any quarter of the Partnership, all cash on hand at the end of such quarter less the amount of cash reserves established by the General Partner in its reasonable discretion that is necessary or appropriate to provide for future cash requirements. Our commitment to our Unitholders is to distribute the increase in our cash flow while maintaining prudent reserves for our operations. Heritage (the predecessor to ETP) paid all quarterly distributions since its inception in 1996 up to and including the quarterly distribution of $0.325 per unit paid on January 14, 2004. Heritage had raised its quarterly distribution over the years from $0.25 per unit in 1996 to $0.325 per unit as of the quarterly distribution paid on January 14, 2004.

Distributions declared during the years ended August 31, 2006, 2005 and 2004 are summarized as follows:

	Record Date	Payment Date	Amount per Unit
Fiscal Year 2006			
	September 30, 2005	October 14, 2005	$ 0.5000
	January 4, 2006	January 13, 2006	$ 0.5500
	March 24, 2006	April 14, 2006	$ 0.5875
	June 30, 2006	July 14, 2006	$ 0.6375
	June 30, 2006 (1)	July 14, 2006	$ 0.0325
Fiscal Year 2005			
	October 7, 2004	October 15, 2004	$ 0.4125
	January 5, 2005	January 14, 2005	$ 0.4375
	March 16, 2005	April 14, 2005	$ 0.4625
	July 8, 2005	July 14, 2005	$ 0.4875
Fiscal Year 2004			
	April 2, 2004	April 14, 2004	$ 0.3500
	July 2, 2004	July 15, 2004	$ 0.3750

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(1) Special SCANA distribution On June 20, 2006, we announced that the Board of Directors of our General Partner declared a special distribution of $0.0325 per Limited Partner Unit related to the proceeds we received in connection with the SCANA litigation settlement (see Notes 6 and 9 to our consolidated financial statements). This distribution was paid on July 14, 2006 to the holders of record of our Common and Class F Units as of the close of business on June 30, 2006. This special one-time payment was approved following a determination of the Litigation Committee of our General Partner to distribute all the net distributable litigation proceeds we received in accordance with the Partnership Agreement. The special distribution also included a payment to the holder of our Class C Units for that amount normally allocated to our General Partner, which was $3.6 million. See discussion in Notes 6 and 9 of our consolidated financial statements for further information.

On September 21, 2006, we announced the declaration of a cash distribution for the fourth quarter ended August 31, 2006 of $0.75 per Common Unit, or $3.00 annually, an increase of $0.45 per Common Unit on an annualized basis. The distribution was paid on October 16, 2006 to Unitholders of record at the close of business on October 5, 2006.

The total amount of distributions (all from Available Cash from our operating surplus) declared relating to the years ended August 31, 2006, 2005 and 2004 are as follows:

	2006	2005	2004
Limited Partners -			
Common Units	$ 248,237	$ 173,802	$ 52,963
Class D Units			5,405
Class C Units (1)	3,599		
Class F Units	3,232		
General Partner -			
2% Ownership	6,981	4,390	1,392
Incentive Distribution Rights	81,722	28,847	3,623
Total distributions declared	$ 343,771	$ 207,039	$ 63,383

(1) Special SCANA distribution see discussion above.

New Accounting Standards

FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes - An Interpretation of FASB Statement No. 109*, (FIN 48). FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with SFAS No. 109. FIN 48 also prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The new FASB standard also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. The evaluation of a tax position in accordance with FIN 48 is a two-step process. The first step is a recognition process whereby the enterprise determines whether it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. In evaluating whether a tax position has met the more-likely-than-not recognition threshold, the enterprise should presume that the position will be examined by the appropriate taxing authority that has full knowledge of all relevant information. The second step is a measurement process whereby a tax position that meets the more-likely-than-not recognition threshold is calculated to determine the amount of benefit to recognize in the financial statements. The tax position is measured at the largest amount of benefit that is greater than 50% likely of being realized upon ultimate settlement. The provisions of FIN 48 are effective for fiscal years beginning after December 15, 2006. Earlier application is permitted as long as the enterprise has not yet issued financial statements, including interim financial statements, in the period of adoption. The provisions of FIN 48 are to be applied to all tax positions upon initial adoption of this standard. Only tax positions that meet the more-likely-than-not recognition threshold at the effective date may be recognized or continue to be recognized upon adoption of FIN 48. The cumulative effect of applying the provisions of FIN 48 should be reported as an adjustment to the opening balance of retained earnings (or other appropriate components of equity or net assets in the statement of financial position) for that fiscal year. We are currently evaluating the statement and have not yet determined the impact of such on our financial statements.

SFAS No. 151*, Inventory Costs an amendment of ARB No. 43, Chapter 4* (SFAS 151). In November 2004, the FASB issued SFAS 151 which amends the guidance in ARB No. 43, Chapter 4, Inventory Pricing. ARB No. 43 previously required that certain costs associated with inventory be treated as current period charges if they were

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determined to be so abnormal as to warrant it. SFAS 151 amends this removing the so abnormal requirement and stating that unallocated overhead costs and other items such as abnormal handling costs and amounts of wasted materials (spoilage) require treatment as current period charges rather than a portion of inventory cost. SFAS 151 is effective for inventory costs incurred during fiscal years beginning after June 15, 2005, with earlier application permitted. The provisions of this statement need not be applied to immaterial items. We do not allocate overhead costs to inventory and management has determined that there are no other material items which require the application of SFAS 151.

SFAS No. 154*, Accounting Changes and Error Correction a replacement of APB Opinion No. 20 and FASB Statement No. 3* (SFAS 154). In May 2005, the FASB issued SFAS 154 which requires that the direct effect of voluntary changes in accounting principle be applied retrospectively with all prior period financial statements presented on the new accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. Indirect effects of a change should be recognized in the period of the change. SFAS 154 is effective for accounting changes and correction of errors made in fiscal years beginning after December 15, 2005. Management will adopt the provisions of SFAS 154 beginning September 1, 2006, as applicable. The impact of SFAS 154 will depend on the nature and extent of any voluntary accounting changes and correction of errors after the effective date, but management does not currently expect SFAS 154 to have a material impact on our consolidated results of operations, cash flows or financial position.

SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments An Amendment of FASB Statements No. 133 and 140* (SFAS 155). SFAS 155 is effective for all financial instruments acquired, issued, or subject to a remeasurement (new basis) event occurring after the beginning of an entity s first fiscal year that begins after September 15, 2006. Early application is permitted only if: (a) it occurs at the beginning of an entity s fiscal year and (b) the entity has not yet issued any interim or annual financial statements for that fiscal year. We intend to adopt this statement when required at the start of fiscal year beginning September 1, 2008. The adoption of this statement is not expected to have a significant impact on us.

SFAS No. 157, *Fair Value Measurement,* (SFAS 157). This new standard provides guidance for using fair value to measure assets and liabilities. The FASB believes the standard also responds to investors requests for expanded information about the extent to which companies measure assets and liabilities at fair value, the information used to measure fair value, and the effect of fair value measurements on earnings. SFAS 157 applies whenever other standards require (or permit) assets or liabilities to be measured at fair value but does not expand the use of fair value in any new circumstances. The standard clarifies that for items that are not actively traded, such as certain kinds of derivatives, fair value should reflect the price in a transaction with a market participant, including an adjustment for risk, not just the company s mark-to-model value. SFAS 157 also requires expanded disclosure of the effect on earnings for items measured using unobservable data. Under SFAS 157, fair value refers to the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants in the market in which the reporting entity transacts. In this standard, the FASB clarifies the principle that fair value should be based on the assumptions market participants would use when pricing the asset or liability. In support of this principle, SFAS 157 establishes a fair value hierarchy that prioritizes the information used to develop those assumptions. The fair value hierarchy gives the highest priority to quoted prices in active markets and the lowest priority to unobservable data, for example, the reporting entity s own data. Under the standard, fair value measurements would be separately disclosed by level within the fair value hierarchy. The provisions of SFAS 157 are effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. Earlier application is encouraged, provided that the reporting entity has not yet issued financial statements for that fiscal year, including any financial statements for an interim period within that fiscal year. We are currently evaluating this statement and have not yet determined the impact of such on our financial statements. We plan to adopt this statement when required at the start of our fiscal year beginning September 1, 2008.

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EITF Issue No. 04-13, *Accounting for Purchases and Sales of Inventory With the Same Counterparty* (EITF 04-13). In EITF 04-13, the Task Force reached a tentative conclusion that inventory purchases and sales transactions with the same counterparty that are entered into in contemplation of one another should be combined for purposes of applying Accounting Principles Board Opinion No. 29, Accounting for Nonmonetary Transactions. The tentative conclusions reached by the Task Force are required to be applied to transactions completed in reporting periods beginning after March 15, 2006. We adopted this EITF during fiscal year 2006 and such adoption did not have a material impact on our results of operations, financial position or cash flows.

EITF Issue No. 06-3, *How Taxes Collected from Customers and Remitted to Governmental Authorities Should be Presented in the Income Statement (that is, Gross Versus Net Presentation)* (EITF 06-3). This accounting guidance requires companies to disclose their policy regarding the presentation of tax receipts on the face of their income statements. The scope of this guidance includes any tax assessed by a governmental authority that is directly imposed on a revenue-producing transaction between a seller and a customer and may include, but is not limited to, sales, use, value added, and some excise taxes (gross receipts taxes are excluded). This guidance is effective for interim and annual reporting periods beginning after December 15, 2006 with earlier application permitted. As a matter of policy, we report such taxes on a net basis. We will adopt this EITF during our 2007 fiscal year.

Critical Accounting Policies and Estimates

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 applied to the specific set of circumstances existing in our business. 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 are critical. Our critical accounting policies are discussed below. For further details on our accounting policies and a discussion of new accounting pronouncements, see Note 3 Significant Accounting Policies and Balance Sheet Detail to our consolidated financial statements in this report.

Use of Estimates. The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to establish accounting policies and make estimates and assumptions that affect reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. As is normal in the natural gas industry, our most current month s financial results for our midstream and transportation and storage segments are estimated using volume estimates and market prices. Actual results could differ from our estimates if the underlying assumptions prove to be incorrect.

Revenue Recognition. Revenues for sales of natural gas, NGLs including propane, and propane appliances, parts, and fittings are recognized at the later of the time of delivery of the product to the customer or the time of sale or installation. Revenue from service labor, transportation, treating, compression, and gas processing, is recognized upon completion of the service. Transportation capacity payments are recognized when earned in the period the capacity is made available. Tank rent is recognized ratably over the period it is earned.

Results from the midstream segment are determined primarily by the volumes of natural gas gathered, compressed, treated, processed, purchased and sold through our pipeline and gathering systems and the level of natural gas and NGL prices. We generate midstream revenues and gross margins principally under fee-based arrangements or other arrangements. Under fee-based arrangements, we receive a fee for natural gas gathering, compressing, treating or processing services. The revenue earned from these arrangements is directly related to the volume of natural gas that flows through our systems and is not directly dependent on commodity prices.

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We also utilize other types of arrangements in our midstream segment, including (i) discount-to-index price arrangements, which involve purchases of natural gas at either (1) a percentage discount to a specified index price, (2) a specified index price less a fixed amount, or (3) a percentage discount to a specified index price less an additional fixed amount, (ii) percentage-of-proceeds arrangements under which we gather and processes natural gas on behalf of producers, selling the resulting residue gas and NGL volumes at market prices and remitting to producers an agreed upon percentage of the proceeds based on an index price, and (iii) keep-whole arrangements where we gather natural gas from the producer, processes the natural gas and sells the resulting NGLs to third parties at market prices. In many cases, we provide services under contracts that contain a combination of more than one of the arrangements described above. The terms of our contracts vary based on gas quality conditions, the competitive environment at the time the contracts are signed and customer requirements. Our contract mix may change as a result of changes in producer preferences, expansion in regions where some types of contracts are more common and other market factors.

Our transportation and storage segment results are determined primarily by the amount of capacity customers reserve as well as the actual volume of natural gas that flows through the transportation pipelines determines transportation and storage segment results. Under transportation contracts, our customers are charged (i) a demand fee, which is a fixed fee for the reservation of an agreed amount of capacity on the transportation pipeline for a specified period of time and which obligates the customer to pay us even if the customer does not transport natural gas on the respective pipeline, (ii) a transportation fee, which is based on the actual throughput of natural gas by the customer, (iii) a fuel retention based on a percentage of gas transported on the pipeline, or (iv) a combination of the three, generally payable monthly. The transportation and storage segment also generates its revenues and margin from the sale and marketing of natural gas to electric utilities, independent power plants, local distribution companies, industrial end-users, and other marketing companies on the HPL system.

We account for our trading activities under the provisions of EITF Issue No. 02-3, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities* (EITF 02-3), which requires revenue and costs related to energy trading contracts to be presented on a net basis in the income statement.

Fair Value of Derivative Commodity Contracts. We utilize various exchange-traded and over-the-counter commodity financial instrument contracts to limit our exposure to margin fluctuations in natural gas, NGL and propane prices and in our trading activities. These contracts consist primarily of commodity forwards, futures, swaps, options and certain basis contracts as cash flow hedging instruments. Certain contracts, are not accounted for as hedges and in accordance with SFAS No. 133 *Accounting for Derivative Instruments and Hedging Activities* (SFAS 133), the gains and losses resulting from changes in the fair value of these contracts are recorded on a current basis on the statement of operations. In our retail propane business, we classify all gains and losses from these derivative contracts entered into for risk management purposes as liquids marketing revenue in the consolidated statement of operations. The gains and losses on the natural gas derivative contracts that are entered into for trading purposes are recognized in the midstream and transportation and storage revenue on a net basis in the consolidated statement of operations. The non-trading gains and losses for natural gas contracts are recorded as cost of products sold in the consolidated statement of operations. On our contracts that are designated as cash flow hedges in accordance with SFAS No. 133, the effective portion of the hedged gain or loss is initially reported as a component of other comprehensive income and is subsequently reclassified into earnings when the physical transaction settles. The ineffective portion of the gain or loss is reported in earnings immediately. We utilize published settlement prices for exchange-traded contracts, quotes provided by brokers, and estimates of market prices based on daily contract activity to estimate the fair value of these contracts. We also use the Black Scholes valuation model to estimate the value of certain options. Changes in the methods used to determine the fair value of these contracts could have a material effect on our results of operations. We do not anticipate future changes in the methods used to determine the fair value of these derivative contracts.

Natural Gas Exchanges. We record exchange receivables and payables when a customer delivers more or less gas into our pipelines than they take out. We primarily estimate the value of our exchanges at prices representing the value of the commodity at the end of the accounting reporting period. Changes in natural gas prices may impact our valuation. Based on our net payable position of $1.5 million as of August 31, 2006, a change in natural gas prices of 10 percent could positively or negatively affect our results of operations by $0.2 million.

Volume Measurement. We record amounts for natural gas gathering and transportation revenue, liquid transportation and handling revenue, natural gas sales and natural gas purchases, and the sale of production based on volumetric calculations. Variances resulting from such calculations are inherent in our business.

Impairment of Long-Lived Assets and Goodwill. Long-lived assets are required to be tested for recoverability whenever events or changes in circumstances indicate that the carrying amount of the asset may not be recoverable.

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Goodwill must be tested for impairment annually or more frequently if events or changes in circumstances indicate that the related asset might be impaired. An impairment loss should be recognized only if the carrying amount of the asset/goodwill is not recoverable and exceeds its fair value.

In order to test for recoverability, we must make estimates of projected cash flows related to the asset which include, but are not limited to, assumptions about the use or disposition of the asset, estimated remaining life of the asset, and future expenditures necessary to maintain the asset s existing service potential. In order to determine fair value, we make certain estimates and assumptions, including, among other things, changes in general economic conditions in regions in which our markets are located, the availability and prices of natural gas and propane supply, our ability to negotiate favorable sales agreements, the risks that natural gas exploration and production activities will not occur or be successful, our dependence on certain significant customers and producers of natural gas, and competition from other midstream companies, including major energy producers. Due to the subjectivity of the assumptions used to test for recoverability and to determine fair value, significant impairment charges could result in the future, thus affecting our future reported net income.

Property, Plant, and Equipment. Maintenance capital expenditures are capital expenditures made to replace partially or fully depreciated assets in order to maintain the existing operating capacity of our assets and to extend their useful lives. Maintenance capital expenditures also include capital expenditures made to connect additional wells to our systems in order to maintain or increase throughput on our existing assets. Growth or expansion capital expenditures are capital expenditures made to expand the existing operating capacity of our assets, whether through construction or acquisition. We treat repair and maintenance expenditures that do not extend the useful life of existing assets as operating expenses as we incur them. Upon disposition or retirement of pipeline components or gas plant components, any gain or loss is recorded to accumulated depreciation. When entire pipeline systems, gas plants or other property and equipment are retired or sold, any gain or loss is included in operations. Depreciation of property, plant and equipment is provided using the straight-line method based on their estimated useful life ranging from 5 to 65 years. Changes in the estimated useful lives of the assets could have a material effect on our results of operation. We do not anticipate future changes in the estimated useful live of our property, plant, and equipment.

Amortization of Intangible Assets. For those intangible assets that do not have indefinite lives, we calculate amortization using the straight-line method over periods ranging from 2 to 15 years. We use amortization methods and determine asset values based on management s best estimate using reasonable and supportable assumptions and projections. Changes in the amortization methods, asset values or estimated lives could have a material effect on our results of operations. We do not anticipate future changes in the estimated useful lives of our intangible assets.

Asset Retirement Obligation. An entity is required to recognize the fair value of a liability for an asset retirement obligation in the period in which it is incurred if a reasonable estimate of fair value can be made. If a reasonable estimate cannot be made in the period the asset retirement obligation is incurred, the liability should be recognized when a reasonable estimate of fair value can be made.

In order to determine fair value, management must make certain estimates and assumptions including, among other things, projected cash flows, a credit-adjusted risk-free rate, and an assessment of market conditions that could significantly impact the estimated fair value of the asset retirement obligation. These estimates and assumptions are very subjective. We have determined that we are obligated by contractual or regulatory requirements to remove assets or perform other remediation upon retirement of certain assets. However, the fair value of our asset retirement obligation cannot currently be reasonably estimated because the settlement dates are indeterminate. We will record an asset retirement obligation in the periods in which it can reasonably determine the settlement dates.

Income Per Limited Partner Unit. Basic net income per limited partner unit is computed in accordance with EITF Issue No. 03-6 (EITF 03-6) *Participating Securities and the Two-Class method under FASB Statement No. 128,* by dividing limited partners interest in net income by the weighted average number of Common and Class F Units outstanding. In periods when our aggregate net income exceeds the aggregate distributions, EITF 03-6 requires us to present earnings per unit as if all of the earnings for the periods were distributed, see Note 4 Net Income Per Limited Partner Unit to the consolidated financial statements of this report. Diluted net income per limited partner unit is computed by dividing limited partners interest in net income, after considering the General Partner s interest, by the weighted average number of Common and Class F Units outstanding and the effect of non-vested restricted units (Unit Grants) granted under the 2004 Unit Plan and predecessor plan computed using the treasury stock method.

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ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market risk includes the risk of loss arising from adverse changes in market rates and prices. We face market risk from commodity variations, risks related to interest rate variations, and to a lesser extent, credit risks. From time to time, we may utilize derivative financial instruments as described below to manage our exposure to such risks.

Commodity Price Risk

We are exposed to commodity price risk from the risk of price changes in the natural gas and NGLs that we buy and sell in our midstream, transportation and storage activities. We control the scope of risk management, marketing and trading activities through a comprehensive set of policies and procedures involving senior levels of management. The audit committee of our Board of Directors has oversight responsibilities for our risk management limits and policies. A risk oversight committee, comprised of the Co-Chief Executive Officers, Chief Financial Officer, Treasurer, President of our midstream and transportation and storage operations, Controller of our midstream and transportation and storage operations, and Senior Vice President Commercial Optimization of our midstream and transportation and storage operations, sets forth risk management policies and objectives. The committee establishes procedures for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of derivative activity and risk exposures. The trading activities are subject to the commodity risk management policy that includes risk management limits, including volume and stop-loss limits, to manage exposure to market risk.

In our retail propane business, the market price of propane is often subject to volatility changes as a result of supply or other market conditions over which we have no control. In the past, price changes have generally been passed along to our propane customers to maintain gross margins, mitigating the commodity price risk. In order to help ensure adequate supply sources are available to us during periods of high demand, we will at times purchase significant volumes of propane during periods of low demand, which generally occur during the summer months, at the then current market price. The propane is then stored at both our customer service locations and in major storage facilities for future resale.

Non-trading Activities

We use a combination of financial instruments including, but not limited to, futures, price swaps, options and basis swaps to manage our exposure to market fluctuations in the prices of natural gas, NGLs and propane. Swaps and futures allow us to protect our margins because corresponding losses or gains in the value of financial instruments are generally offset by gains or losses in the physical market.

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

We manage our price risk related to future physical purchase or sale commitments for our producer services activities by entering into either corresponding physical delivery contracts or financial instruments with an objective to balance our future commitments and significantly reduce our risk to the movement in prices. However, we are subject to counterparty risk for both the physical and financial contracts. We also utilize forward purchase contracts to acquire a portion of the propane that we resell to our customers, which allows us to manage our exposure to unfavorable changes in commodity prices and to assure adequate physical supply. We account for such physical contracts under the normal purchases and sales exception of SFAS 133.

In connection with the acquisition of HPL, we acquired certain physical forward contracts that contain embedded options that we have not designated as a normal purchase and sale nor were the contracts designated as hedges under SFAS 133. These contracts are marked to market, along with the financial options that offset them, and are recorded in the statement of operations and on our consolidated balance sheet as a component of price risk management assets and liabilities.

In our midstream and transportation and storage segments, we account for certain of our derivatives as cash flow hedges under SFAS 133. All derivatives are recognized on the balance sheet at fair value as price risk management assets and liabilities. The changes in the fair value of price risk management assets and liabilities that are designated, documented as cash flow hedges, and determined to be effective are recorded through other comprehensive income (loss). The effective portion of the hedge gain or loss is initially reported as a component of other comprehensive income (loss)

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and when the physical transaction settles, any gain or loss previously recorded in other comprehensive income (loss) on the derivative is recognized in earnings in the consolidated statement of operations. The ineffective portion of the gain or loss is reported immediately in cost of products sold in the consolidated statement of operations. For those derivatives that do not qualify for hedge accounting, the change in market value is recorded as cost of products sold in the consolidated statement of operations.

We also attempt to maintain balanced positions in our midstream and transportation and storage segments to protect us from the volatility in the energy commodities markets. To the extent open commodity positions exist, fluctuating commodity prices can impact our financial results either favorably or unfavorably.

Trading Activities

We have a risk management policy that provides for our marketing and trading operations to execute limited strategies. These activities are monitored independently by our risk management function and must take place within predefined limits and authorizations. Certain strategies are considered trading for accounting purposes and are executed with the use of a combination of financial instruments including, but not limited to, basis and gas daily contracts. These instruments are within the guidelines of the risk management policy which has been approved by our Board of Directors. The trading activities are a compliment to the producer services operations and are accounted for in net revenues on the consolidated statement of operations. We follow the applicable provisions of EITF 02-3, which requires that gains and losses on derivative instruments be shown net in the statement of operations if the derivative instruments are held for trading purposes. Net realized and unrealized gains and losses from the financial contracts and the impact of price movements are recognized in the consolidated statement of operations as other revenue. Changes in the assets and liabilities from the trading activities result primarily from changes in the market prices, newly originated transactions, and the timing and settlement of contracts. Forward physical contracts associated with the trading activities are marked to market and included in revenue on our consolidated statement of operations because they do not meet normal purchases and sales exception of SFAS 133.

Commodity-related Derivatives

Our commodity-related price risk management assets and liabilities as of August 31, 2006 were as follows:

	Commodity	Notional Volume MMBTU	Maturity	Fair Value
Mark to Market Derivatives				
(Non-Trading)				
Basis Swaps IFERC/NYMEX	Gas	33,711,140	2006-2009	$ (6,247)
Swing Swaps IFERC	Gas	(37,220,448)	2006-2008	2,618
Fixed Swaps/Futures	Gas	3,607,500	2006-2007	(170)
Forward Physical Contracts	Gas	(7,986,000)	2006-2008	(21,653)
Options	Gas	(1,046,000)	2006-2008	21,653
Forwards/Swaps (in Gallons)	Propane	24,066,000	2006-2007	199
(Trading)				
Basis Swaps IFERC/NYMEX	Gas	(2,572,500)	2006-2008	21,995
Swing Swaps IFERC	Gas		2006	(31)
Forward Physical Contracts	Gas	(455,000)	2006	(68)
Cash Flow Hedging Derivatives				
(Non-Trading)				
Basis Swaps IFERC/NYMEX	Gas	(34,585,000)	2006-2007	(2,987)
Fixed Swaps/Futures	Gas	(37,872,500)	2006-2007	2,043

Credit Risk

We maintain credit policies with regard to our counterparties that we believe significantly minimize overall credit risk. These policies include an evaluation of potential counterparties financial condition (including credit ratings), collateral requirements under certain circumstances and the use of standardized agreements which allow for netting of positive and negative exposure associated with a single counterparty.

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Our counterparties consist primarily of financial institutions, major energy companies and local distribution companies (LDCs). This concentration of counterparties may impact our overall exposure to credit risk, either positively or negatively in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions. Based on our policies, exposures, credit and other reserves, we do not anticipate a material adverse effect on financial position or results of operations as a result of counterparty performance.

Sensitivity analysis

The table below summarizes our commodity-related financial positions and values as of August 31, 2006. The table assumes a hypothetical 10% change in the underlying price of the commodity and its effect.

	Notional Volume MMBTU	Fair Value	Effect of Hypothetical 10% Change
Non-Trading Derivatives			
Fixed Swaps/Futures	(34,265,000)	$ 1,873	$ 42,615
Basis Swaps IFERC/NYMEX	(873,860)	(9,234)	1,594
Swing Swaps IFERC	(37,220,448)	2,618	514
Options	(1,046,000)	21,653	5,189
Forward Physical Contracts	(7,986,000)	(21,653)	5,189
Propane Forwards/Swaps (in Gallons)	24,066,000	199	2,766
Trading Derivatives			
Swing Swaps IFERC		(31)	205
Basis Swaps IFERC/NYMEX	(2,572,500)	21,995	701
Forward Physical Contracts	(455,000)	(68)	75

The table below summarizes our positions and values as of August 31, 2005. It also assumes a hypothetical 10% change in the underlying price of the commodity and its effect.

	Notional Volume MMBTU	Fair Value	Effect of Hypothetical 10% Change
Nymex Futures/ Fixed Price	(43,937,500)	$ (148,006)	$ 51,962
Basis Swaps	(96,846,114)	53,840	9,788
Fixed Price Index Swaps	5,910,000	36,455	6,472
Options	(1,776,000)	78,941	16,034
Swing Swaps	(67,841,503)	(10,085)	1,428
Forward Contracts	(21,340,000)	(78,500)	16,034

The fair values of the commodity-related financial positions have been determined using independent third party prices, readily available market information, broker quotes and appropriate valuation techniques. Non-trading positions offset physical exposures to the cash market; none of these offsetting physical exposures are included in the above tables. Price-risk sensitivities were calculated by assuming a theoretical 10 percent change (increase or decrease) in price regardless of term or historical relationships between the contractual price of the instruments and the underlying commodity price. Results are presented in absolute terms and represent a potential gain or loss in our consolidated results of operations or in accumulated other comprehensive income. In the event of an actual 10 percent change in prompt month natural gas prices, the fair value of our total derivative portfolio may not change by 10 percent due to factors such as when the financial instrument settles and the location to which the financial instrument is tied (i.e., basis swaps).

Interest Rate Risk

We are exposed to changes in interest rates, primarily as a result of our variable rate debt and, in particular, our revolving credit facility. To the extent interest rates increase, our interest expense for our revolving debt will also increase. At August 31, 2006, we had $1.2 billion of variable rate debt outstanding that is not hedged. A hypothetical change of 100 basis points in the underlying interest rate would have an effect of $12.0 million in increased interest expense on an annual basis.

Treasury locks with a notional amount of $100.0 million were outstanding as of August 31, 2006 and had a fair value of $0.1 million which was recorded as a component of price risk management assets on the consolidated balance sheet. A hypothetical change of 100 basis points on the underlying interest rates of the treasury locks outstanding at August 31, 2006 would have an effect of $8.0 million on the value of the locks. Forward starting interest rate swaps with a notional amount of $600.0 million were also outstanding as of August 31, 2006 and had a fair value of $8.2 million which was recorded as a component of price risk management liabilities on the consolidated balance sheet. A hypothetical change of 100 basis points on the underlying interest rates of the interest rate swaps outstanding as of August 31, 2006 would have an effect of $47.0 million on the value of the swaps. In connection with the Titan acquisition, we assumed a three year LIBOR interest swap with a notional amount of $125.0 million. The fair value of this swap at August 31, 2006 was approximately $0.5 million. A hypothetical change of 100 basis points on the underlying interest rate would have an effect of $2.9 million on the value of the swap.

We also have long-term debt instruments which are typically issued at fixed interest rates. Prior to or when these debt obligations mature, we may refinance all or a portion of such debt at then-existing market interest rates which may be more or less than the interest rates on the maturing debt.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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Energy Transfer Partners, L.P. and Subsidiaries

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Partners

Energy Transfer Partners, L.P.

We have audited the accompanying consolidated balance sheets of Energy Transfer Partners, L.P. (a Delaware limited partnership) and subsidiaries, as of August 31, 2006 and 2005 and the related consolidated statements of operations, comprehensive income, partners capital, and cash flows for each of the three years in the period ended August 31, 2006. These financial statements are the responsibility of the Partnership s management. Our responsibility is to express an opinion on these financial statements 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 Energy Transfer Partners, L.P. and subsidiaries as of August 31, 2006 and 2005 and the results of their operations and their cash flows for each of the three years in the period ended August 31, 2006 in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Energy Transfer Partners, L.P. s internal control over financial reporting as of August 31, 2006, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated November 6, 2006 expressed unqualified opinions on the effectiveness of internal control over financial reporting and management s evaluation thereof.

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma

November 6, 2006

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(in thousands, except unit data)

	August 31, 2006	August 31, 2005
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 26,041	$ 24,914
Marketable securities	2,817	3,452
Accounts receivable, net of allowance for doubtful accounts	675,545	847,028
Accounts receivable from related companies	897	4,479
Inventories	387,140	291,445
Deposits paid to vendors	87,806	65,034
Exchanges receivable	23,221	35,623
Price risk management assets	56,139	138,961
Prepaid expenses and other	42,198	35,636
Total current assets	1,301,804	1,446,572
PROPERTY, PLANT AND EQUIPMENT, net	3,313,649	2,440,565
LONG-TERM PRICE RISK MANAGEMENT ASSETS	2,192	41,687
ADVANCES TO AND INVESTMENT IN AFFILIATES	41,344	37,353
GOODWILL	604,409	324,019
INTANGIBLES AND OTHER ASSETS, net	182,392	112,159
OTHER LONG-TERM ASSETS	9,223	13,103
Total assets	$ 5,455,013	$ 4,415,458

The accompanying notes are an integral part of these consolidated financial statements.

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(in thousands, except unit data)

	August 31, 2006	August 31, 2005
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES:		
Working capital facility	$	$ 17,026
Accounts payable	603,140	818,775
Accounts payable to related companies	650	1,073
Exchanges payable	24,722	33,772
Customer advances and deposits	108,836	138,442
Accrued and other current liabilities	201,017	84,154
Price risk management liabilities	36,918	104,772
Income taxes payable		2,063
Deferred income taxes	629	
Current maturities of long-term debt	40,578	39,349
Total current liabilities	1,016,490	1,239,426
LONG-TERM DEBT, less current maturities	2,589,124	1,675,705
LONG-TERM PRICE RISK MANAGEMENT LIABILITIES	1,728	30,517
LONG-TERM AFFILIATED PAYABLE		2,005
DEFERRED INCOME TAXES	106,842	111,185
OTHER NON-CURRENT LIABILITIES	2,110	13,284
MINORITY INTERESTS	1,857	17,144
COMMITMENTS AND CONTINGENCIES (Note 9)		
	3,718,151	3,089,266
PARTNERS CAPITAL:		
General Partner	82,450	49,384
Limited Partners:		
Common Unitholders (110,726,999 and 106,889,904 units authorized, issued and outstanding at August 31, 2006 and 2005, respectively)	1,647,345	1,362,125
Class C Unitholders (0 and 1,000,000 units authorized, issued and outstanding at August 31, 2006 and 2005, respectively)		
Class E Unitholders (8,853,832 authorized, issued and outstanding at August 31, 2006 and 2005 held by subsidiary and reported as treasury units)		
	1,729,795	1,411,509
Accumulated other comprehensive income (loss), per accompanying statements	7,067	(85,317)
Total partners capital	1,736,862	1,326,192
Total liabilities and partners capital	$ 5,455,013	$ 4,415,458

The accompanying notes are an integral part of these consolidated financial statements.

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per unit and unit data)

	Year Ended August 31, 2006	Year Ended August 31, 2005	Year Ended August 31, 2004
REVENUES:			
Midstream and transportation and storage	$ 6,877,512	$ 5,383,625	$ 1,966,803
Propane	893,647	709,904	342,523
Other	87,937	75,269	37,631
Total revenues	7,859,096	6,168,798	2,346,957
COSTS AND EXPENSES:			
Cost of products sold midstream and transportation and storage	5,963,422	4,911,366	1,771,321
Cost of products sold propane	580,978	448,853	199,640
Cost of products sold other	23,916	21,296	10,463
Operating expenses	422,989	319,554	147,374
Depreciation and amortization	117,415	92,943	48,599
Selling, general and administrative	107,505	62,735	30,471
Total costs and expenses	7,216,225	5,856,747	2,207,868
OPERATING INCOME	642,871	312,051	139,089
OTHER INCOME (EXPENSE):			
Interest expense, net of interest capitalized	(113,857)	(93,017)	(41,190)
Loss on extinguishment of debt		(9,550)	
Equity in earnings (losses) of affiliates	(479)	(376)	363
Gain (loss) on disposal of assets	851	(330)	(1,006)
Interest and other income, net	14,620	631	509
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE AND MINORITY INTERESTS	544,006	209,409	97,765
Income tax expense	(25,920)	(7,295)	(4,481)
INCOME FROM CONTINUING OPERATIONS BEFORE MINORITY INTERESTS	518,086	202,114	93,284
Minority interests	(2,234)	(731)	(295)
INCOME FROM CONTINUING OPERATIONS	515,852	201,383	92,989
DISCONTINUED OPERATIONS:			
Income from discontinued operations		5,498	6,163
Gain on sale of discontinued operations, net of income tax expense		142,469	
Total income from discontinued operations		147,967	6,163

NET INCOME		515,852		349,350		99,152
GENERAL PARTNER S INTEREST IN NET INCOME		118,985		45,442		8,938
LIMITED PARTNERS INTEREST IN NET INCOME	$	396,867	$	303,908	$	90,214
BASIC NET INCOME PER LIMITED PARTNER UNIT						
Limited Partners income from continuing operations	$	3.16	$	1.51	$	1.62
Limited Partners income from discontinued operations				1.10		0.11
NET INCOME PER LIMITED PARTNER UNIT	$	3.16	$	2.61	$	1.73
BASIC AVERAGE NUMBER OF UNITS OUTSTANDING		109,036,265		97,646,351		52,228,742
DILUTED NET INCOME PER LIMITED PARTNER UNIT						
Limited Partners income from continuing operations	$	3.15	$	1.50	$	1.62
Limited Partners income from discontinued operations				1.10		0.11
NET INCOME PER LIMITED PARTNER UNIT	$	3.15	$	2.60	$	1.73
DILUTED AVERAGE NUMBER OF UNITS OUTSTANDING		109,334,778		97,831,017		52,283,210

The accompanying notes are an integral part of these consolidated financial statements.

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(in thousands)

	Year Ended August 31, 2006	Year Ended August 31, 2005	Year Ended August 31, 2004
NET INCOME	$ 515,852	$ 349,350	$ 99,152
OTHER COMPREHENSIVE INCOME:			
Reclassification adjustment for gains and losses on derivative instruments included in net income accounted for as hedges, before tax benefits of $91, $0, and $0 for the years ended August 31, 2006, 2005 and 2004, respectively.	(74,598)	25,280	(3,396)
Change in value of derivative instruments accounted for as hedges, before tax expenses of $(204), $0 and $0 for the years ended August 31, 2006, 2005 and 2004, respectively.	167,729	(111,617)	3,481
Change in value of available-for-sale securities, before tax benefits of $1, $0 and $0 for the years ended August 31, 2006, 2005 and 2004, respectively.	(635)	988	(53)
Income tax expense related to items of other comprehensive income	(112)		
Comprehensive income	$ 608,236	$ 264,001	$ 99,184
Reconciliation of Accumulated Other Comprehensive Income (Loss)			
Balance, beginning of period	$ (85,317)	$ 32	$
Current period reclassification to earnings	(74,507)	25,280	(3,396)
Current period change	166,891	(110,629)	3,428
Balance, end of period	$ 7,067	$ (85,317)	$ 32
Components of Accumulated Other Comprehensive Income (Loss)			
Other comprehensive income (loss) related to:			
Commodity-related derivative hedges net of tax expense of $203, $0 and $0 for the years ended August 31, 2006, 2005 and 2004, respectively	$ 2,095	$ (84,523)	$ 85
Interest rate derivative hedges net of tax benefit of $90, $0 and $0 for the years ended August 31, 2006, 2005 and 2004, respectively	4,672	(1,729)	
Available-for-sale securities net of tax benefit of $1, $0 and $0 for for the years ended August 31, 2006, 2005 and 2004, respectively	300	935	(53)
Balance, end of period	$ 7,067	$ (85,317)	$ 32

The accompanying notes are an integral part of these consolidated financial statements.

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF PARTNERS CAPITAL

(in thousands)

	General			Limited Partner Capital			
	Partner	Common	Class C	Class D	Class E	Class F	Special
Balance, August 31, 2003	$ 192	$ 180,896	$	$	$	$	$
Distribution to parent		(208,927)					
Distributions to partners	(5,015)	(52,963)		(5,405)			
Merger with Heritage	(896)	103,631		205,382			38,000
Conversion of Class E Units		(158,235)			158,235		
Class E Units held by subsidiary and reported as treasury units					(158,235)		
Issuance of Common Units		528,129					
General Partner capital contribution	23,542	(1,027)		(284)			
Issuance of Common Units in connection with certain acquisitions		734					
Conversion of Class D and Special Units		256,007		(218,007)			(38,000)
Other		42					
Net income	8,938	71,900		18,314			
Balance, August 31, 2004	26,761	720,187					
Distributions to partners	(33,237)	(173,802)					
General Partner capital contribution	10,418						
Issuance of Common Units in connection with certain acquisitions		2,500					
Issuance of Common Units		507,724					
Unit-based compensation expense		1,608					
Net income	45,442	303,908					
Balance, August 31, 2005	49,384	1,362,125					
Distributions to partners	(88,703)	(248,237)	(3,599)			(3,232)	
General Partner capital contribution	2,784						
Issuance of Common and Class F Units to Energy Transfer Equity, LP		38,907				93,476	
Issuance of Common Units in connection with certain acquisitions		4,000					
Conversion of Class F to Common Units		93,268				(93,268)	
Unit-based compensation expense		7,038					
Net income	118,985	390,244	3,599			3,024	
Balance, August 31, 2006	$ 82,450	$ 1,647,345	$	$	$	$	$

The accompanying notes are an integral part of these consolidated financial statements.

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Year Ended August 31, 2006	Year Ended August 31, 2005	Year Ended August 31, 2004
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 515,852	$ 349,350	$ 99,152
Reconciliation of net income to net cash provided by operating activities:			
Depreciation and amortization related to continuing and discontinued operations	117,415	94,490	50,848
Amortization of deferred finance costs charged to interest expense	2,807	4,049	2,642
Loss on extinguishment of debt		9,550	
Provision for bad debts	1,723	5,523	1,667
(Gain) loss on disposal of assets	(851)	330	1,006
Gain on sale of discontinued operations before income tax expense		(146,401)	
Unit-based compensation	7,038	1,608	42
Undistributed losses (earnings) of affiliates and other	480	342	(363)
Deferred income taxes	(3,827)	1,289	(3,723)
Minority interests	1,381	540	502
Net change in operating assets and liabilities, net of acquisitions	(98,134)	(151,252)	10,922
Net cash provided by operating activities	543,884	169,418	162,695
CASH FLOWS FROM INVESTING ACTIVITIES:			
Cash paid for acquisitions, net of cash acquired	(586,185)	(1,131,844)	(681,835)
Working capital settlement on prior year acquisitions	19,653		
Capital expenditures	(680,164)	(196,459)	(109,688)
Proceeds from the sale of discontinued operations		191,606	
Advances to and investment in affiliates	(4,651)	(2,355)	(322)
Proceeds from the sale of assets	6,941	5,303	1,108
Net cash used in investing activities	(1,244,406)	(1,133,749)	(790,737)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from borrowings	2,829,748	2,954,034	894,079
Principal payments on debt	(1,917,451)	(2,337,931)	(510,084)
Proceeds from borrowings from affiliates		174,624	
Payments on borrowings from affiliates		(174,624)	
Net proceeds from issuance of Common Units	132,383	507,724	528,129
Capital contribution from General Partner	2,784	10,418	22,231
Distributions to parent			(206,071)
Debt issuance costs	(2,044)	(19,706)	(8,236)
Distributions to partners	(343,771)	(207,039)	(63,383)
Net cash provided by financing activities	701,649	907,500	656,665
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	1,127	(56,831)	28,623
CASH AND CASH EQUIVALENTS, beginning of period	24,914	81,745	53,122

CASH AND CASH EQUIVALENTS, end of period	$	26,041	$	24,914	$	81,745

The accompanying notes are an integral part of these consolidated financial statements.

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Dollar amounts in thousands, except unit and per unit data)

1. OPERATIONS AND ORGANIZATION:

Financial Statement Presentation

The accompanying consolidated financial statements of Energy Transfer Partners, L.P. and subsidiaries (the Partnership or ETP) presented herein for the years ended August 31, 2006, 2005 and 2004, have been prepared in accordance with accounting principles generally accepted in the United States of America and pursuant to the rules and regulations of the Securities and Exchange Commission. We consolidate all majority-owned subsidiaries. We recognize a minority interest liability and minority interest expense for all partially-owned consolidated subsidiaries. All significant intercompany transactions and accounts are eliminated in consolidation.

The consolidated financial statements of the Partnership presented herein for the year ended August 31, 2006 include the results of operations for La Grange Acquisition, L.P., which conducts business under the assumed name of Energy Transfer Company (ETC OLP), Heritage Operating, L.P. (referenced herein as HOLP) and Heritage Holdings, Inc. (HHI) for the entire period from September 1, 2005 through August 31, 2006. The results of operations for Titan Energy Partners, L.P. (Titan) are included since the date of acquisition (June 1, 2006).

The consolidated financial statements of the Partnership presented herein for the year ended August 31, 2005 include the results of operations for ETC, HOLP and HHI for the entire period from September 1, 2004 through August 31, 2005 and the Houston Pipeline System (HPL) since the date of acquisition (January 26, 2005).

The financial statement information presented for the year ended August 31, 2004 includes the results of operations for ETC OLP for the entire period from September 1, 2003 to August 31, 2004. However, the results of operations for HOLP and HHI are only included from the date of the Energy Transfer Transactions (January 20, 2004) to August 31, 2004 (see Note 2). In addition, on June 2, 2004, ETC OLP acquired the TUFCO System (now referred to as the ET Fuel System) from TXU Fuel Company, a subsidiary of TXU Corp. The accompanying financial statements include the results of operations of the ET Fuel System beginning June 2, 2004, and the Bossier Pipeline (now known as the East Texas Pipeline) since June 21, 2004. The comparability of the accompanying consolidated financial statements is also affected by other acquisitions and the disposition of ETC Oklahoma Pipeline, Ltd. (Elk City) as described in Note 2.

We also own varying undivided interests in certain pipelines. Ownership of these pipelines has been structured as an ownership of an undivided interest in assets, not as an ownership interest in a partnership, limited liability company, joint venture or other forms of entities. Each owner controls marketing and invoices separately, and each owner is responsible for any loss, damage or injury that may occur to their own customers. As a result, we apply proportionate consolidation for our interests in these entities.

Certain prior period amounts have been reclassified to conform with the 2006 presentation. These reclassifications had no impact on net income or total partners capital.

Business Operations

In order to simplify the obligations of Energy Transfer Partners under the laws of several jurisdictions in which we operate, our activities are conducted through three subsidiary operating partnerships, ETC OLP, a Texas limited partnership engaged in midstream and transportation and storage natural gas operations, HOLP, a Delaware limited partnership engaged in retail and wholesale propane operations, and Titan, a Delaware limited partnership engaged in retail propane operations (collectively the Operating Partnerships). The Partnership, the Operating Partnerships, and their subsidiaries are collectively referred to in this report as we , us , ETP , Energy Transfer Partners or the Partnership.

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ETC OLP owns and operates, through its wholly and majority-owned subsidiaries, natural gas gathering systems, natural gas intrastate pipeline systems and gas processing plants and is engaged in the business of purchasing, gathering, transporting, processing, and marketing natural gas and natural gas liquids (NGLs) in the states of Texas, Louisiana and, formerly, Oklahoma. ETC OLP was owned 99.9% by ETP subsequent to the Energy Transfer Transactions and 0.1% by ETC OLP s General Partner, LA GP, LLC, a wholly-owned subsidiary of ETP. ETC OLP was contributed to Heritage on January 19, 2004, and became a wholly-owned subsidiary of ETP.

As of August 31, 2006, ETC OLP owns an interest in and operates approximately 12,000 miles of natural gas gathering and transportation pipelines with an additional 600 miles under construction, three natural gas processing plants, two of which are currently connected to its gathering systems, fourteen natural gas treating facilities and three natural gas storage facilities.

Our midstream segment focuses on gathering, compression, treating, blending, processing and marketing of natural gas. Its operations are currently concentrated in the Austin Chalk trend of southeast Texas, the Permian Basin of west Texas, the Barnett Shale in north Texas and the Bossier Sands in east Texas.

Our transportation and storage segment focuses on the transportation of natural gas between major markets from various natural gas producing areas through connections with other pipeline systems as well as through the Oasis Pipeline, the East Texas Pipeline, the Fort Worth Basis Pipeline, the natural gas pipeline and storage assets that are referred to as the ET Fuel System, and the natural gas pipeline and storage assets of the HPL System.

Our propane segments consist of HOLP and Titan which collectively sell propane and propane-related products to more than 1,000,000 active residential, commercial, industrial, and agricultural customers from 442 customer locations in 41 states. HOLP is also a wholesale propane supplier in the United States and in Canada, the latter through its participation in MP Energy Partnership, a Canadian partnership, in which we own a 60% interest, engaged in lower-margin wholesale distribution and in supplying HOLP s northern U.S. locations. HOLP buys and sells financial instruments for its own account through its wholly owned subsidiary, Heritage Energy Resources, L.L.C. (Resources).

2. SIGNIFICANT ACQUISITIONS AND DISPOSITIONS:

Significant Acquisitions:

Energy Transfer Transactions

On January 20, 2004, Heritage Propane Partners, L.P., (Heritage) and La Grange Energy, L.P. (now known as Energy Transfer Equity, L.P. (ETE)) completed the series of transactions whereby ETE contributed ETC OLP to Heritage in exchange for cash, Common Units, Class D Units and Special Units of Heritage. Simultaneously, ETE acquired the General Partner of Heritage, Energy Transfer Partners GP, L.P. (formerly U.S. Propane, L.P.) and Energy Transfer Partners, L.L.C. (formerly U.S. Propane, L.L.C.) from their owners, and coupled with the Heritage Limited Partner interests ETE received, thereby gained control of Heritage. Simultaneous with these transactions, Heritage purchased the outstanding stock of Heritage Holdings, Inc. (HHI) from the owners of Energy Transfer Partners GP, L.P.

Subsequent to the Energy Transfer Transactions, Heritage changed its name to Energy Transfer Partners, L.P., and began trading on the New York Stock Exchange under the ticker symbol ETP . The name change and new ticker symbol were effective March 1, 2004.

The Energy Transfer Transactions were accounted for as a reverse acquisition in accordance with Statement of Financial Accounting Standard No. 141, *Business Combinations* (SFAS 141). Although Heritage was the surviving parent entity for legal purposes, ETC OLP was the acquirer for accounting purposes. As a result, ETC OLP s historical financial statements are now our historical financial statements of the registrant. Consequently, the accompanying financial statements do not reflect 100% of the results of Heritage as those

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results prior to January 19, 2004 (the date of the Energy Transfer Transactions) are not included. The operations of Heritage prior to the Energy Transfer Transactions are referred to as Heritage. In accordance with Emerging Issues Task Force (EITF) 90-13 *Accounting for Simultaneous Common Control Mergers* and SFAS 141, the assets and liabilities of Heritage were initially recorded at fair value to the extent acquired by ETE through its acquisition of the General Partner and approximately 35.4% of the limited partner interests of Heritage. The assets and liabilities of ETC OLP have been recorded at historical cost. Although the partners capital accounts of ETC OLP became the capital accounts of the Partnership, Heritage s partnership structure and partnership units survive. Accordingly, the partners capital accounts of ETC OLP were restated based on the General Partner interests and units received by ETE in the Energy Transfer Transactions.

The acquisition of HHI by Heritage was accounted for as a capital transaction as the primary asset held by HHI was 8,853,832 Common Units on a post-split basis following the two-for-one split completed on March 15, 2005. Following the acquisition of HHI by Heritage, these Common Units were converted to Class E Units. The Class E Units are recorded as treasury units in the consolidated financial statements.

ETE received Special Units in the Energy Transfer Transactions as consideration for the East Texas Pipeline project which was in progress at that time. Upon completion of the East Texas Pipeline in June 2004, the Special Units, which initially had no value assigned, were converted to Common Units, which resulted in additional consideration being recorded. The additional consideration adjusted the percent of Heritage acquired to 41.5% and resulted in an additional fair value step-up to Heritage s assets of approximately $38,000 as determined in accordance with EITF 90-13.

The excess purchase price over Heritage s cost was determined as follows:

Net book value of Heritage at January 20, 2004	$ 239,102
Historical goodwill at January 20, 2004	(170,500)
Equity investment from public offering	355,948
Treasury Class E Unit purchase	(157,340)
	267,210
Percent of Heritage acquired by La Grange Energy	41.5%
Equity interest acquired	$ 110,892
Fair market value of Limited Partner Units	$ 668,534
Purchase price of General Partner Interest	30,000
Equity investment from public offering	355,948
Treasury Class E Unit purchase	(157,340)
	897,142
Percent of Heritage acquired by La Grange Energy	41.5%
Fair value of equity acquired	372,314
Net book value of equity acquired	110,892
Excess purchase price over Heritage cost	$ 261,422

The excess purchase price over Heritage cost was allocated as follows:

Property, plant and equipment (25 year life)	$ 35,269
Customer lists (15 year life)	18,926
Trademarks	19,251

Goodwill	187,976
	$ 261,422

Management obtained an independent valuation and made the final modifications to the purchase price during the first quarter of fiscal year 2005.

Fiscal year 2006 acquisitions

On November 10, 2005, we acquired the remaining 2% limited partnership interests in HPL for $16,560 in cash. The purchase price was allocated to property, plant and equipment and the minority interest liability associated with the 2% limited partner interests was eliminated. As a result, HPL became a wholly-owned subsidiary of ETC OLP. We also reached a settlement agreement with AEP in November 2005 related to certain inventory and working capital matters associated with the acquisition. The terms of the agreement were not material in relation to our financial position or results of operations.

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Prior to November 2005, we owned a 50% interest in South Texas Gas Gathering, a joint venture that owned an 80% interest in the Dorado System, a 61-mile gathering system located in South Texas. We purchased the remaining 50% equity interest in South Texas Gas Gathering in November 2005 for $675.

On June 1, 2006, we acquired all the propane operations of Titan Energy Partners, LP and Titan Energy, GP LLC (collectively Titan) for cash of approximately $548,000, after working capital adjustments and net of cash acquired, and liabilities assumed of approximately $46,000. This acquisition was initially financed by borrowings under the ETP Revolving Credit Facility. Titan s propane assets primarily consist of retail propane operations in 33 states conducted from 146 district locations located in high growth areas of the U.S. The addition of the Titan assets expanded our retail propane operations into six additional states and several new operating territories in which we did not previously have operations. This expansion will further reduce the impact on the propane operations from weather patterns in any one area of the U.S., while continuing our focus on conducting the retail propane operations in attractive high-growth areas. We accounted for the Titan acquisition as a business combination using the purchase method of accounting in accordance with the provisions of SFAS 141. The purchase price has been initially allocated based on the estimated fair value of the individual assets acquired and the liabilities assumed at the date of the acquisition based on the preliminary results of an independent appraisal. We expect to complete the purchase allocation during our first or second quarter of fiscal year 2007 upon the completion of the independent appraisal. Pro forma results of operations due to the Titan acquisition are discussed below.

During the fiscal year ended August 31, 2006, HOLP and Titan collectively acquired substantially all of the assets of eight propane businesses. The aggregate purchase price for these acquisitions totaled $28,902 which included $20,572 of cash paid, net of cash acquired, 99,955 Common Units issued valued at $4,000 and liabilities assumed of $4,327. In the aggregate, these acquisitions are not material for pro forma disclosure purposes. The cash paid for acquisitions was financed primarily with the HOLP Senior Revolving Acquisition Facility.

The following table presents the allocation of the acquisition cost to the assets acquired and liabilities assumed based on their fair values for these fiscal year 2006 acquisitions:

	Titan June 2006	Midstream and Transportation and Storage Acquisitions	Propane-related Acquisitions (Aggregated)
Cash and equivalents	$ 24,458	$	$ 3
Accounts receivable	20,304	396	1,702
Inventory	11,417	20	795
Prepaid and other current assets	2,055	4	83
Investments in unconsolidated affiliate		(50)	
Price risk management assets	720		
Property, plant, and equipment	202,598	308	19,276
Intangibles and other assets	74,532		5,342
Goodwill	278,149		1,701
Other long-term assets	5,055		
Total assets acquired	619,288	678	28,902
Accounts payable	(18,337)	(211)	
Accrued expenses	(14,992)	(10)	(1,748)
Customer advances and deposits	(11,356)		
Other current liabilities			
Current maturities of long term debt	(964)		
Long-term debt	(692)		(2,579)
Minority interest		16,667	
Total liabilities assumed	(46,341)	16,446	(4,327)
Net assets acquired	$ 572,947	$ 17,124	$ 24,575

We recorded the following intangible assets in conjunction with these acquisitions:

Customer lists (3-15 years)	$ 37,333
Non-compete agreements (5 to 10 years)	2,315
Software	2,200
Total amortized intangible assets	41,848
Trademarks and trade names	35,395
Goodwill	279,850
Other assets	2,631
Total intangible assets and goodwill acquired	$ 359,724

Goodwill was warranted because these acquisitions enhance our current operations and certain acquisitions are expected to reduce costs through synergies with existing operations. We expect all of the goodwill acquired to be tax deductible.

We obtained the final independent valuation for the fiscal year 2005 HPL acquisition (as discussed below) and made the final allocations of the purchase price to the acquired assets during the second quarter of fiscal year 2006. The final adjustments, which did not have a material impact on our financial position, resulted in a reduction of $45,820 to the amount allocated to pad gas and an increase of an equal amount to acquired depreciable assets.

Fiscal year 2005 acquisitions

In November 2004, we acquired the Texas Chalk and Madison Systems from Devon Gas Services for $63,022 in cash which was principally financed with $60,000 from the then existing ETC OLP Revolving Credit Facility. The total purchase price was $65,067 which included $63,022 of cash paid and liabilities assumed of $2,045. These assets include approximately 1,800 miles of gathering and mainline pipeline systems, four natural gas treating plants, condensate stabilization facilities and an 80 MMcf/d gas processing plant. These assets will be integrated into the Southeast Texas System and are expected to provide increased throughput capacity to our existing midstream assets. The acquisition was not material for pro forma disclosure purposes.

In January 2005, we acquired the controlling interests in HPL from American Electric Power Corporation (AEP) for approximately $825,000 subject to working capital adjustments. Under the terms of the transaction, the Partnership, through ETC OLP, our wholly-owned subsidiary, acquired all but a 2% limited partner interest in HPL. We financed this acquisition through a combination of cash on hand, borrowings under our credit facilities and a private placement with institutional investors of $350,000 of Partnership Common Units. In addition, we acquired working inventory of natural gas stored in the Bammel storage facilities. The total purchase price of $1,350,212 (which included $1,039,521 of cash paid), net of cash acquired and liabilities assumed of $344,663, (including $800 in estimated acquisition costs), was allocated to the assets acquired and liabilities assumed. The HPL System consists of approximately 4,200 miles of intrastate pipeline with aggregate capacity of 2.4 Bcf/d, substantial storage facilities and related transportation assets. The acquisition enables us to expand our current transportation systems into areas where we previously did not have a presence and, in combination with our current midstream assets, provides the premier producing basins in Texas with direct access to the Houston Ship Channel corridor. HPL is included in our transportation and storage operating segment.

Prior to June 29, 2005, ETC OLP owned a 50% interest in Vantex Gas Pipeline Company, LLC and a 50.5% interest in Vantex Energy Services, Ltd. On June 29, 2005, ETC OLP purchased the remaining interest in both Vantex Gas Pipeline, LLC and Vantex Energy Services, Ltd. for approximately $3,839 of cash paid, net of cash acquired. The Vantex Gas system is located in East Texas and consists of approximately 250 miles of pipeline. Vantex Energy Services provides energy related marketing services to small and medium sized producers and end users on the Vantex Gas Pipeline system. The acquisition was not material for pro forma disclosure purposes.

During the year ended August 31, 2005, HOLP acquired substantially all of the assets of ten propane businesses. The aggregate purchase price for these acquisitions totaled $30,772 which included $25,462 of cash paid, net of cash acquired, 120,550 Common Units on a post-split basis issued valued at $2,500 and liabilities assumed of $2,810. In the aggregate, these acquisitions are not material for pro forma disclosure purposes. The cash paid for acquisitions was financed primarily with the HOLP Senior Revolving Acquisition Facility.

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The following table presents the allocation of the acquisition cost to the assets acquired and liabilities assumed based on their fair values for these acquisitions:

	Texas Chalk and Madison Systems November 2004	Initial HPL Acquisition January 2005	Vantex June 2005	HOLP Acquisitions (Aggregated)
Cash and equivalents	$	$ 191	$ 1,081	$ 5
Accounts receivable		321,214	6,066	875
Inventory		132,095		584
Other current assets		8,672	1	215
Investments in unconsolidated affiliate		32,940		
Price risk management assets		30,300		
Property, plant, and equipment	65,067	823,360	4,479	18,592
Intangibles		1,440		5,971
Goodwill				4,535
Total assets acquired	65,067	1,350,212	11,627	30,777
Accounts payable	(525)	(253,784)	(5,404)	(233)
Accrued expenses	(1,520)	(18,344)	(91)	(181)
Other current liabilities		(11,829)	(132)	(227)
Other liabilities		(15,277)		
Price risk management liabilities		(30,300)		
Long-term debt				(2,169)
Minority interest		(15,129)		
Total liabilities assumed	(2,045)	(344,663)	(5,627)	(2,810)
Net assets acquired	$ 63,022	$ 1,005,549	$ 6,000	$ 27,967

We recorded the following intangible assets in conjunction with these acquisitions:

Customer lists (3-15 years)	$ 3,456
Non-compete agreements (5 to 10 years)	1,326
Total amortized intangible assets	4,782
Trademarks and trade names	2,629
Goodwill	4,535
Total intangible assets and goodwill acquired	$ 11,946

Goodwill was warranted because these acquisitions enhance our current operations and certain acquisitions are expected to reduce costs through synergies with existing operations. We assigned all of the goodwill acquired to the retail propane segment of HOLP. We expect the entire $4,535 of goodwill acquired to be tax deductible.

The purchase prices were allocated based on the estimated fair values of the assets acquired and liabilities assumed at the date of the acquisition.

During the third quarter of fiscal year 2005, we completed a verification of the working gas inventory contained in the storage facilities we acquired in two acquisitions during fiscal year 2004 and adjusted the preliminary allocations of the purchase prices to reflect the verified amounts.

During fiscal year 2006, we adjusted the preliminary allocations for the HPL acquisition (1) to reflect the working capital settlement with AEP occurring in the first quarter of fiscal year 2006 and (2) to reflect the final purchase price allocation as discussed above.

Fiscal year 2004 acquisitions

On June 2, 2004, ETC OLP acquired the transportation assets of TXU Fuel Company (formerly the TUFCO System now referred to as the ET Fuel System) for $498,571 in cash. The assets include approximately 2,000 miles of intrastate pipeline and related storage facilities located in Texas, with a total system capacity of 1.3 billion cubic feet or natural gas per day. The purchase price was funded with borrowings under ETC OLP s amended debt agreement. These assets allow ETC OLP to provide multiple services to producers in four major producing areas of Texas, as well as providing access to major natural gas markets. In addition, these assets

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are expected to provide us significant growth opportunities going forward. The acquisition was accounted for using the purchase method under SFAS 141. The purchase price was initially allocated based on the estimated fair values of the individual assets acquired and the liabilities assumed at the date of the acquisition. The final allocation of the purchase price was completed in the third quarter of fiscal year 2005 upon the completion of an independent appraisal. Our unaudited pro forma results of operations presented below are as if the ET Fuel System had been acquired at the beginning of the periods presented are presented below.

During the period from January 20, 2004 to August 31, 2004, HOLP acquired substantially all of the assets of three propane companies. The aggregate purchase price for these acquisitions totaled $16,967, which included liabilities assumed of $268. In the aggregate, these acquisitions are not material for pro forma disclosure purposes. These acquisitions were financed primarily with the HOLP Senior Revolving Acquisition Facility and were accounted for by the purchase method under SFAS 141.

The assets acquired and purchase price allocation of acquisitions during the year ended August 31, 2004 are as follows:

	ET Fuel System June 2, 2004	HOLP Acquisitions (Aggregated) January 20, 2004 to August 31, 2004
Accounts receivable	$	$ 1,612
Inventory		335
Other current assets	57	
Property, plant and equipment	499,789	8,024
Intangibles		1,560
Goodwill	10,327	5,437
Total assets acquired	510,173	16,968
Accrued expenses	(758)	(52)
Other current liabilities		(1)
Deposits from vendor	(750)	
Exchanges payable	(10,094)	
Long-term debt		(215)
Total liabilities assumed	(11,602)	(268)
Net assets acquired	$ 498,571	$ 16,700

The results of operations for these acquisitions are included in our consolidated statement of operations from the date of the respective acquisition.

Pro Forma Results of Operations (Unaudited)

The following unaudited pro forma consolidated results of operations for the year ended August 31, 2006 are presented as if the Titan acquisition had been made on September 1, 2005. The pro forma consolidated results of operations for the year ended August 31, 2005 are presented as if the Titan and HPL acquisitions had been made on September 1, 2004. The pro-forma consolidated results of operations for the year ended August 31, 2004, are presented as if the HPL acquisition, the ET Fuel System acquisition and the Energy Transfer Transactions had been made on September 1, 2003. The pro forma effects of the Titan acquisition have not been included in the pro forma consolidated results of operations for the year ended August 31, 2004. The pro forma consolidated net income and earnings per unit include the income from discontinued operations as presented on the consolidated statements of operations for the years ended August 31, 2005 and 2004.

	Year Ended August 31, 2006	Year Ended August 31, 2005	Year Ended August 31, 2004
Revenues	$ 8,194,053	$ 8,210,903	$ 6,316,534
Net income	$ 536,085	$ 730,208	$ 125,897
Limited Partners interest in net income	$ 410,689	$ 674,111	$ 115,811
Basic earnings per Limited Partner Unit	$ 3.09	$ 4.15	$ 1.33
Diluted earnings per Limited Partner Unit	$ 3.08	$ 4.14	$ 1.33

Included in the pro forma results of operations for our fiscal year ended August 31, 2005 is approximately $350.2 million of Titan income related to the cancellation of debt through Titan s bankruptcy process, net of $24.9 million of Titan reorganization expenses and $10.8 million of Titan fresh start expenses. This income is not excluded from our pro forma income for the year ended August 31, 2005 as it does not result directly from the Titan acquisition. However, this income is non-recurring in nature and we do not expect to realize similar income in the future.

The pro forma consolidated results of operations include adjustments to give effect to depreciation on the step-up of property, plant and equipment, amortization of customer lists, interest expense on acquisition debt, and certain other adjustments. The pro forma consolidated results of operations do not include the purchase of the remaining 50% of Vantex Gas Pipeline Company, LLC and the 50.5% interest in Vantex Energy Services, Ltd. on June 29, 2005 as the impact is not material. In addition, the acquisition of the remaining 2% interest of HPL and the eight propane businesses that were acquired during the year ended August 31, 2006 and the propane acquisitions and Texas Chalk and Madison Systems acquisitions that were completed during the years ended August 31, 2005 and 2004, are not included in the pro forma consolidated results of operations above as the impact of such acquisitions is not material. The pro forma information is not necessarily indicative of the results of operations that would have occurred had the transactions been made at the beginning of the periods presented or the future results of the combined operations.

Dispositions

On April 14, 2005, we sold our Oklahoma gathering, treating and processing assets, referred to as the Elk City System, for $191,606 in cash and recorded a gain on the sale during the fiscal year 2005 of $142,469, net of income taxes of $1,829. The Elk City System was included in our midstream segment. The sale of the Elk City System has been accounted for as discontinued operations in accordance with Statement of Financial Accounting Standards No. 144, *Accounting for the Impairment or Disposal of Long-lived Assets*. These results are presented as net amounts in the consolidated statements of operations for the year with prior periods restated to conform to the current presentation. Selected operating results for these discontinued operations are presented in the following table:

	Year Ended August 31, 2005	Year Ended August 31, 2004
Revenues	$ 105,542	$ 135,297
Cost and expenses	(100,044)	(129,134)
Income from discontinued operations	$ 5,498	$ 6,163

3. <u>SIGNIFICANT ACCOUNTING POLICIES AND BALANCE SHEET DETAIL</u>:

Revenue Recognition

Revenues for sales of natural gas, natural gas liquids (NGLs) including propane, and propane appliances, parts, and fittings are recognized at the later of the time of delivery of the product to the customer or the time of sale or installation. Revenue from service labor, transportation, treating, compression, and gas processing, is recognized upon completion of the service. Transportation capacity payments are recognized when earned in the period the capacity is made available. Tank rent is recognized ratably over the period it is earned.

Results from the midstream segment are determined primarily by the volumes of natural gas gathered, compressed, treated, processed, purchased and sold through our pipeline and gathering systems and the level of natural gas and NGL prices. We generate midstream revenues and gross margins principally under fee-based or other arrangements in which we receive a fee for natural gas gathering, compressing, treating or processing services. The revenue earned from these arrangements is directly related to the volume of natural gas that flows through our systems and is not directly dependent on commodity prices.

We also utilize other types of arrangements in our midstream segment, including (i) discount-to-index price arrangements, which involve purchases of natural gas at either (1) a percentage discount to a specified index

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price, (2) a specified index price less a fixed amount or (3) a percentage discount to a specified index price less an additional fixed amount, (ii) percentage-of-proceeds arrangements under which we gather and process natural gas on behalf of producers, sell the resulting residue gas and NGL volumes at market prices and remit to producers an agreed upon percentage of the proceeds based on an index price, and (iii) keep-whole arrangements where we gather natural gas from the producer, process the natural gas and sell the resulting NGLs to third parties at market prices. In many cases, we provide services under contracts that contain a combination of more than one of the arrangements described above. The terms of our contracts vary based on gas quality conditions, the competitive environment at the time the contracts are signed and customer requirements. Our contract mix may change as a result of changes in producer preferences, expansion in regions where some types of contracts are more common and other market factors.

We conduct our marketing operations through our producer services business, in which we market the natural gas that flows through our assets, referred to as on-system gas. We also attract other customers by marketing volumes of natural gas that do not move through our assets, referred to as off-system gas. For both on-system and off-system gas, we purchase natural gas from natural gas producers and other supply points and sell that natural gas to utilities, industrial consumers, other marketers and pipeline companies, thereby generating gross margins based upon the difference between the purchase and resale prices.

We have a risk management policy that provides for our marketing and trading operations to execute limited strategies. These activities are monitored independently by our risk management function and must take place within predefined limits and authorizations. Certain strategies are considered trading activities for accounting purposes and are accounted for on a net basis in revenues on the consolidated statements of operations. Our trading activities include purchasing and selling natural gas and the use of financial instruments, including basis contracts and gas daily contracts.

We account for our trading activities under the provisions of EITF Issue No. 02-3, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities* (EITF 02-3), which requires revenue and costs related to energy trading contracts to be presented on a net basis in the statement of operations. As a result of our trading activities, discussed in Note 10, and the use of derivative financial instruments that may not qualify for hedge accounting in our midstream and transportation and storage segments, the degree of earnings volatility that can occur may be significant, favorably or unfavorably, from period to period. We attempt to manage this volatility through the use of daily position and profit and loss reports provided to the risk management committee which includes members of senior management, and predefined limits and authorizations set forth by our risk management policy.

Our transportation and storage results are determined primarily by the amount of capacity our customers reserve as well as the actual volume of natural gas that flows through the transportation pipelines. Under transportation contracts, our customers are charged (i) a demand fee, which is a fixed fee for the reservation of an agreed amount of capacity on the transportation pipeline for a specified period of time and which obligates the customer to pay even if the customer does not transport natural gas on the respective pipeline, (ii) a transportation fee, which is based on the actual throughput of natural gas by the customer, (iii) a fuel retention based on a percentage of gas transported on the pipeline, or (iv) a combination of the three, generally payable monthly. Our transportation and storage segment also generates its revenues and margin from fees charged for storing customers working natural gas in our storage facilities, primarily on the ET Fuel system, and to a lesser extent, at HPL.

Our transportation and storage segment also generates revenues and margin from the sale of natural gas to electric utilities, independent power plants, local distribution companies, industrial end-users, and other marketing companies on the HPL System. Generally, HPL purchases its natural gas from the market, including purchases from the midstream segment s producer services, and from producers at the wellhead. To the extent the natural gas is obtained from producers, it is purchased at a discount to a specified price and is typically resold to customers at a price based on a published index.

We engage in natural gas storage transactions in which we seek to find and profit from pricing differences that occur over time utilizing the Bammel storage reservoir on its HPL System. We purchase physical natural gas and then sell financial contracts at a price sufficient to cover our carrying costs and provide for a gross profit margin. Since the acquisition of HPL, we have continually managed our positions to enhance the future profitability of our storage position. We expect margins from the HPL System to be higher during the periods from November to March of each year and lower during the period from April through October of each year due to the increased demand for natural gas during colder weather. However, we cannot assure that management s expectations will be fully realized in the future and in what time period, due to various factors including weather, availability of natural gas in regions in which we operate, competitive factors in the energy industry, and other issues.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period.

The natural gas industry conducts its business by processing actual transactions at the end of the month following the month of delivery. Consequently, the most current month s financial results for the midstream and transportation and storage segments are estimated using volume estimates and market prices. Any differences between estimated results and actual results are recognized in the following month s financial statements. Management believes that the operating results estimated for the year ended August 31, 2006 represent the actual results in all material respects.

Some of the other more significant estimates made by management include, but are not limited to, the timing of certain forecasted transactions that are hedged, allowances for doubtful accounts, the fair value of derivative instruments, useful lives for depreciation and amortization, purchase accounting allocations and subsequent realizability of intangible assets, deferred taxes, and general business and medical self-insurance reserves. Actual results could differ from those estimates.

Cash, Cash Equivalents and Supplemental Cash Flow Information

Cash and cash equivalents include all cash on hand, demand deposits, and investments with original maturities of three months or less. We consider cash equivalents to include short-term, highly liquid investments that are readily convertible to known amounts of cash and which are subject to an insignificant risk of changes in value.

We place our cash deposits and temporary cash investments with high credit quality financial institutions. At times, such balances may be in excess of the Federal Deposit Insurance Corporation (FDIC) insurance limit.

The net change in cash due to changes in operating assets and liabilities (net of acquisitions) is comprised as follows:

	Year Ended August 31,		
	2006	**2005**	**2004**
Accounts receivable	$ 189,719	$ (242,885)	$ (101,976)
Accounts receivable from related companies	3,717	(4,445)	331
Inventories	(83,448)	(105,441)	35,457
Deposits paid to vendors	(22,772)	(62,011)	16,030
Exchanges receivable	12,402	(18,412)	(7,479)
Prepaid expenses and other	(27,574)	(4,650)	2,449
Intangibles and other assets	(999)	(433)	(1,499)
Other long-term assets	(1,738)	(1,834)	
Accounts payable	(295,332)	297,968	58,278
Accounts payable to related companies	(467)	(5,194)	599
Customer advances and deposits	(41,179)	112,429	14,410
Exchanges payable	(9,050)	9,320	1,436
Accrued and other current liabilities	74,333	3,722	(4,324)
Other long-term liabilities	(13,179)	(834)	688
Income taxes payable	(2,063)	(189)	(315)
Price risk management liabilities, net	119,496	(128,363)	(3,163)

Net change in assets and liabilities, net of effect of acquisitions	$ (98,134)	$ (151,252)	$ 10,922

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Noncash financing and supplemental cash flow information is as follows:

	Year Ended August 31, 2006	2005	2004
NONCASH FINANCING ACTIVITIES:			
Notes payable incurred on noncompete agreements	$ 4,234	$ 2,168	$ 215
Issuance of Common Units in connection with certain acquistions	$ 4,000	$ 2,500	$ 734
General Partner capital contribution	$	$	$ 1,311
Contributed assets	$	$	$ 1,743
Distributions payable to parent	$	$	$ 2,856
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:			
Cash paid during the period for interest, net of $12,605, $191 and $926 capitalized for August 31, 2006, 2005 and 2004, respectively	$ 121,329	$ 87,589	$ 37,944
Cash paid during the period for income taxes	$ 38,131	$ 7,538	$ 7,227

Marketable Securities

Marketable securities we own are classified as available-for-sale securities and are reflected as a current asset on the consolidated balance sheet at fair value.

Accounts Receivable

Our midstream and transportation and storage operations deal with counterparties that are typically either investment grade or are otherwise secured with a letter of credit or other form of security (corporate guaranty prepayment or master set off agreement). Management reviews midstream and transportation and storage accounts receivable balances bi-weekly. Credit limits are assigned and monitored for all counterparties of the midstream and transportation and storage operations. Management believes that the occurrence of bad debt in our accounts receivable of the midstream and transportation and storage segments was not significant at the end of the 2006 and 2005 fiscal years; therefore, an allowance for doubtful accounts for the midstream and transportation and storage segments was not deemed necessary. Bad debt expense related to these receivables is recognized at the time an account is deemed uncollectible. There was $975, $0 and $123 in bad debt expense recorded during the years ended August 31, 2006, 2005 and 2004, respectively, in the midstream and transportation and storage segments.

We enter into netting arrangements with counterparties of derivative contracts to mitigate credit risk. Transactions are confirmed with the counterparty and the net amount is settled when due. Amounts outstanding under these netting arrangements are presented on a net basis in the consolidated balance sheets.

HOLP and Titan grant credit to their customers for the purchase of propane and propane-related products. Included in accounts receivable are trade accounts receivable arising from HOLP s retail and wholesale propane and Titan s retail propane operations and receivables arising from liquids marketing activities. Accounts receivable for retail and wholesale propane segments are recorded as amounts are billed to customers less an allowance for doubtful accounts. The allowance for doubtful accounts for the retail and wholesale propane segments is based on management s assessment of the realizability of customer accounts, based on the overall creditworthiness of our customers and any specific disputes.

Accounts receivable consisted of the following:

	August 31, 2006	August 31, 2005
Accounts receivable - midstream and transportation and storage	$ 570,569	$ 782,090
Accounts receivable - propane	108,976	69,014
Less allowance for doubtful accounts	(4,000)	(4,076)
Total, net	$ 675,545	$ 847,028

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The activity in the allowance for doubtful accounts for the retail and wholesale propane segments consisted of the following:

	Year Ended August 31, 2006	Year Ended August 31, 2005	Year Ended August 31, 2004
Balance, beginning of the period	$ 4,076	$ 1,667	$
Provision for loss on accounts receivable	1,723	5,523	1,667
Accounts receivable written off, net of recoveries	(1,799)	(3,114)	
Balance, end of period	$ 4,000	$ 4,076	$ 1,667

The HOLP accounts receivable as of January 20, 2004 were established at estimated fair value in connection with the Energy Transfer Transactions. The Titan accounts receivable as of June 1, 2006 were established at estimated fair value in connection with the Titan acquisition.

Inventories

Inventories consist principally of natural gas held in storage valued at the lower of cost or market utilizing the weighted-average cost method. Propane inventories are valued at the lower of cost or market utilizing the weighted-average cost of propane delivered to the customer service locations, including storage fees and inbound freight costs. The cost of appliances, parts, and fittings is determined by the first-in, first-out method. Inventories consisted of the following:

	August 31, 2006	August 31, 2005
Natural gas, propane and other NGLs	$ 371,430	$ 277,209
Appliances, parts and fittings and other	15,710	14,236
Total inventories	$ 387,140	$ 291,445

Exchanges

Exchanges consist of natural gas and NGL delivery imbalances with others. These amounts, which are valued at market prices, turn over monthly and are recorded as exchanges receivable or exchanges payable on our consolidated balance sheets. Management believes market value approximates cost.

Property, Plant and Equipment

Property, plant and equipment is stated at cost less accumulated depreciation. Depreciation is computed using the straight-line method over the estimated useful lives of the assets. Expenditures for maintenance and repairs that do not add capacity or extend the useful life are expensed as incurred. Expenditures to refurbish assets that either extend the useful lives of the asset or prevent environmental contamination are capitalized and depreciated over the remaining useful life of the asset. Additionally, we capitalize certain costs directly related to the installation of company-owned propane tanks and construction of assets including internal labor costs, interest and engineering costs. Upon disposition or retirement of pipeline components or natural gas plant components, any gain or loss is recorded to accumulated depreciation. When entire pipeline systems, gas plants or other property and equipment are retired or sold, any gain or loss is included in our results of operations.

We review long-lived assets for impairment at least annually and whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. If such a review should indicate that the carrying amount of long-lived assets is not recoverable, we reduce the carrying amount of such assets to fair value. No impairment of long-lived assets was required during the periods presented.

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Components and useful lives of property, plant and equipment were as follows (excluding assets held for sale):

	August 31, 2006	August 31, 2005
Land and improvements	$ 63,220	$ 39,551
Buildings and improvements (10 to 30 years)	66,739	46,829
Pipelines and equipment (10 to 65 years)	1,757,103	1,574,519
Natural gas storage (40 years)	91,177	40,817
Bulk storage, equipment and facilities (3 to 30 years)	108,834	58,825
Tanks and other equipment (5 to 30 years)	472,944	346,924
Vehicles (5 to 10 years)	120,710	81,998
Right of way (20 to 65 years)	104,650	90,683
Furniture and fixtures (3 to 10 years)	16,283	11,995
Linepack	24,821	25,100
Pad Gas	57,327	102,557
Other (5 to 10 years)	27,395	17,893
	2,911,203	2,437,691
Less Accumulated depreciation	(242,137)	(136,804)
	2,669,066	2,300,887
Plus Construction work-in-process	644,583	139,678
Property, plant and equipment, net	$ 3,313,649	$ 2,440,565

Capitalized interest is included for pipeline construction projects. Interest is capitalized based on the current borrowing rate of our revolving credit facility. A total of $12,605, $191 and $926 of interest was capitalized for pipeline construction projects for the years ended August 31, 2006, 2005 and 2004, respectively.

Depreciation expense for the years ended August 31, 2006, 2005 and 2004 was $107,148, $83,827 and $42,454, respectively.

Asset Retirement Obligation

We account for our asset retirement obligations in accordance with Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations,* (SFAS 143). SFAS 143 requires us to record the fair value of an asset retirement obligation as a liability in the period a legal obligation for the retirement of tangible long-lived assets is incurred, typically at the time the assets are placed into service. A corresponding asset is also recorded and depreciated over the life of the asset. After the initial measurement, an entity would recognize changes in the amount of the liability resulting from the passage of time and revisions to either the timing or amount of estimated cash flows.

We have completed the assessment of SFAS 143, and have determined that we are obligated by contractual requirements to remove facilities or perform other remediation upon retirement of certain assets. Determination of the amounts to be recognized is based upon numerous estimates and assumptions, including expected settlement dates, future retirement costs, future inflation rates, and the credit-adjusted risk-free interest rates. However, management is not able to reasonably determine the fair value of the asset retirement obligations as of August 31, 2006 or August 31, 2005 because the settlement dates were indeterminable. An asset retirement obligation will be recorded in the periods management can reasonably determine the settlement dates.

We adopted FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations* (FIN 47) on August 31, 2006. FIN 47 clarified that the term conditional asset retirement obligation , as used in SFAS No. 143, refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement of the obligation are uncertain. These conditional obligations were not previously addressed by SFAS 143. FIN 47 requires us to accrue the fair value of a liability for the conditional asset retirement obligation when incurred generally upon acquisition, construction or development and/or through the normal operation of the asset. Uncertainty about the timing and/or method of settlement of a conditional asset retirement should be factored into the measurement of the liability when a range of scenarios can be determined. FIN 47 clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. The adoption of FIN 47 did not have a material impact on our consolidated results of operations, cash flows or financial position.

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Goodwill

Goodwill is associated with acquisitions made for our midstream, transportation and storage, and retail propane segments. Of the $604,409 balance in goodwill, $303,870 is expected to be tax deductible. Goodwill is tested for impairment annually at August 31, in accordance with Statement of Accounting Standards No. 142, *Goodwill and Other Intangible Assets,* (SFAS 142). Based on the annual impairment tests performed in the fourth fiscal quarter, there was no impairment as of August 31, 2006, 2005 or 2004. The changes in the carrying amount of goodwill for the years ended August 31, 2006 and 2005 were as follows:

	Midstream	Transportation and Storage	Retail Propane	Total
Balance as of August 31, 2004	$ 13,409	$	$ 300,311	$ 313,720
Fair value adjustment for final purchase allocation related to the Energy Transfer Transactions			(4,842)	(4,842)
Goodwill acquired during the year		10,327	4,814	15,141
Balance as of August 31, 2005	13,409	10,327	300,283	324,019
Goodwill acquired during the year			280,390	280,390
Balance as of August 31, 2006	$ 13,409	$ 10,327	$ 580,673	$ 604,409

Goodwill acquired during the year includes, as applicable, final purchase price adjustments for prior year acquisitions. The final assessment of asset values related to the Titan acquisition is expected to be completed in the first or second quarter of fiscal year 2007 upon the completion of the final independent appraisal. There is no guarantee that the preliminary allocation will not change.

The final assessment of asset values related to the Energy Transfer Transactions and the ET Fuel acquisition was completed during the first and third quarters of fiscal year 2005, respectively. The determination of the final fair values resulted in adjustments to the allocations made in 2004 and consisted of changes from the initial determined as follows:

	ET Fuel Acquisition	Energy Transfer Transactions
Increase (decrease) in goodwill	$ 10,327	$ (4,842)
Increase in intangibles	$	$ 10,034
Increase in accrued expenses	$ (233)	$
Increase in exchanges payable	$ (10,094)	$
Decrease in property and equipment	$	$ (5,192)

Investment in Affiliates

We own interests in a number of related businesses that are accounted for using the equity method. In general, we use the equity method of accounting for an investment in which we have a 20% to 50% ownership and exercise significant influences over, but do not control, the investee s operating and financial policies.

Prior to June 29, 2005, ETC OLP owned a 50% interest in Vantex Gas Pipeline Company, LLC and a 50.5% interest in Vantex Energy Services, Ltd. These investments were accounted for under the equity method of accounting. On June 29, 2005 we bought the remaining 50% interest in Vantex Gas Pipeline and the remaining 49.5% interest of Vantex Energy Services, Ltd. The results of operations of the 100% owned entities are recognized on a consolidated basis from the date of acquisition. The Vantex system is located in East Texas and is composed of approximately 250 miles of pipeline. Vantex Energy Services provides energy related marketing services to small and medium sized producers and end users on the Vantex Gas Pipeline system.

We also own a 49% interest in Ranger Pipeline, L.P. (Ranger), which owns a 50% interest in Mountain Creek Joint Venture (Mountain Creek). Mountain Creek is located in North Texas and is composed of approximately 15 miles of pipeline. Mountain Creek supplies gas to an electric generation plant and earns the majority of its yearly income between the months of June and October. We account for our investment in Ranger using the equity method of accounting.

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As a result of the HPL acquisition (see Note 2), we acquired a 50% ownership interest in Mid-Texas Pipeline Company (Mid-Texas) which owns approximately 139 miles of transportation pipeline that connects various receipt points in south Texas to delivery points at the Katy Hub. This pipeline has a throughput capacity of 500 MMcf/d. We do not exercise management control over Mid-Texas, and, therefore, the investment is accounted for using the equity method of accounting.

On July 18, 2005, we entered into a propane joint venture agreement. We contributed cash of $2,304 and a note payable of $2,000 for our 50% interest in this joint venture. This investment is accounted for using the equity method of accounting.

We entered into a joint venture to own a 50% interest in NSL Energy Marketing (NSL), a limited partnership, in June 2006. The joint venture was formed to market the capacity of the recently completed north side loop pipeline in north Texas. We account for our investment in NSL using the equity method of accounting.

Intangibles and Other Assets

Intangibles and other assets are stated at cost net of amortization computed on the straight-line method. We eliminate from our balance sheet the gross carrying amount and the related accumulated amortization for any fully amortized intangibles in the year they are fully amortized. Components and useful lives of intangibles and other assets were as follows:

	August 31, 2006		August 31, 2005	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Amortized intangible assets -				
Noncompete agreements (5 to 15 years)	$ 31,593	$ (13,012)	$ 29,278	$ (8,051)
Customer lists (3 to 15 years)	87,480	(11,640)	50,148	(6,612)
Financing costs (3 to 15 years)	20,128	(4,441)	18,084	(1,891)
Consulting agreements (2 to 7 years)	132	(122)	132	(75)
Other (10 years)	2,677	(422)	477	(191)
Total	142,010	(29,637)	98,119	(16,820)
Unamortized intangible assets -				
Trademarks	64,842		29,447	
Other assets	5,177		1,413	
Total intangibles and other assets	$ 212,029	$ (29,637)	128,979	$ (16,820)

Aggregate amortization expense of intangible assets was $10,267, $9,443 and $6,145 for the years ended August 31, 2006, 2005 and 2004, respectively. The estimated aggregate amortization expense for the next five fiscal years is $12,476 for 2007; $11,400 for 2008; $10,373 for 2009; $8,385 for 2010, and $7,649 for 2011.

We review amortizable intangible assets for impairment at whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable in accordance with Statement of Accounting Standards No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* (SFAS 144). If such a review should indicate that the carrying amount of amortizable intangible assets is not recoverable, we reduce the carrying amount of such assets to fair value. We review non-amortizable intangible assets for impairment annually at August 31, or more frequently if circumstances dictate, in accordance with SFAS 144. No impairment of intangible assets was required for the years ended of August 31, 2006, 2005 or 2004.

Customer Advances and Deposits

Deposits or advances are received from our customers as prepayments for natural gas deliveries in the following month and from our propane customers as security or prepayments for future propane deliveries. Prepayments and security deposits may also be required when customers exceed their credit limits or do not qualify for open credit. Advances and deposits received from customers were $108,836 and $138,442 as of August 31, 2006 and 2005, respectively.

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Fair Value of Financial Instruments

The carrying amounts of accounts receivable and accounts payable approximate their fair value. Price risk management assets and liabilities are recorded at fair value. Based on the estimated borrowing rates currently available to us and our subsidiaries for long-term loans with similar terms and average maturities, the aggregate fair value and carrying amount of long-term debt at August 31, 2006 was $2,589,918 and $2,629,702 respectively. At August 31, 2005 the aggregate fair value and carrying amount of long-term debt was $1,722,519 and $1,715,054, respectively.

Shipping and Handling Costs

In accordance with EITF No. 00-10, *Accounting for Shipping and Handling Fees and Costs,* we have classified $108,409, $89,030 and $35,895 from producer payments for natural gas, compression and treating, which can be considered handling costs, as revenue for the years ended August 31, 2006, 2005 and 2004, respectively. Shipping and handling costs related to fuel sold are included in cost of sales. The remaining costs of approximately $69,647, $50,137 and $19,834 included in operating expenses reflect the cost of fuel consumed for compression and treating for the years ended August 31, 2006, 2005 and 2004, respectively. We do not separately charge propane shipping and handling costs to customers.

Costs and Expenses

Costs of products sold include actual cost of fuel sold adjusted for the effects of our hedging and other commodity derivative activities, storage fees and inbound freight on propane, and the cost of appliances, parts, and fittings. Operating expenses include all costs incurred to provide products to customers, including compensation for operations personnel, insurance costs, vehicle maintenance, advertising costs, shipping and handling costs related to propane, purchasing costs, and plant operations. Selling, general and administrative expenses include all partnership related expenses and compensation for executive, partnership, and administrative personnel.

Income Taxes

Energy Transfer Partners, L.P. is a limited partnership. As a result, our earnings or losses, to the extent not included in a taxable subsidiary, for federal and state income tax purposes are included in the tax returns of the individual partners. Net earnings for financial statement purposes may differ significantly from taxable income reportable to Unitholders as a result of differences between the tax basis and financial reporting basis of assets and liabilities, in addition to the allocation requirements related to taxable income under the Partnership Agreement.

We are generally not subject to income tax. We are, however, subject to a statutory requirement that our non-qualifying income (including income such as derivative gains from trading activities, service income, tank rentals and others) cannot exceed 10% of our total gross income, determined on a calendar year basis under the applicable income tax provisions. If the amount of our non-qualifying income exceeds this statutory limit, we would be taxed as a corporation. Accordingly, certain activities that generate non-qualified income are conducted through taxable corporate subsidiaries (C corporations). These C corporations are subject to federal and state income tax and pay the income taxes related to the results of their operations. For the periods ended August 31, 2006, 2005 and 2004, our non-qualifying income did not, or was not expected to, exceed the statutory limit.

Those subsidiaries which are taxable corporations follow the asset and liability method of accounting for income taxes in accordance with Statement of Financial Accounting Standards No. 109, *Accounting for Income Taxes* (SFAS 109). Under SFAS 109, deferred income taxes are recorded based upon differences between the financial reporting and tax bases of assets and liabilities and are measured using the enacted tax rates and laws that will be in effect when the underlying assets are received and liabilities settled.

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On May 18, 2006, the Governor of Texas signed into law House Bill 3 (HB-3) which modifies the existing franchise tax law. The modified franchise tax will be computed by subtracting either costs of goods sold or compensation expense, as defined in HB-3, from gross revenue to arrive at a gross margin. The resulting gross margin will be taxed at a one percent tax rate. HB-3 has also expanded the definition of tax paying entities to include limited partnerships such as ours. HB-3 becomes effective for activities occurring on or after January 1, 2007. Based on our initial analysis, we do not believe HB-3 will have a significant adverse impact on our financial position or operating cash flows.

Accounting for Derivative Instruments and Hedging Activities

We have established a formal risk management policy in which derivative financial instruments are employed in connection with an underlying asset, liability and/or anticipated transaction. We apply Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities* (SFAS 133) as amended to account for our derivative financial instruments. This statement requires that all derivatives be recognized in the balance sheet as either an asset or liability measured at fair value. Special accounting for qualifying hedges allows a derivative s gains and losses to offset related results on the hedged item in the statement of operations and requires that a company must formally document, designate and assess the effectiveness of transactions that receive hedge accounting treatment. For further discussion and detail of our derivative instruments and/or hedging activities see Note 10 Price Risk Management Assets and Liabilities .

Cash flows from derivatives accounted for as cash flow hedges are reported as cash flow from operating activities, in the same category as the cash flows from the items being hedged.

We use a combination of financial instruments including, but not limited to, futures, price swaps, options and basis swaps to manage our exposure to market fluctuations in the prices of natural gas and NGLs. We enter into these financial instruments with brokers who are clearing members with NYMEX and directly with counterparties in the over-the-counter (OTC) market. We are subject to margin deposit requirements under the OTC agreements and NYMEX positions. NYMEX requires brokers to obtain an initial margin deposit based on an expected volume of the trade when the financial instrument is initiated. This amount is paid to the broker by both counterparties of the financial instrument to protect the broker from default by one of the counterparties when the financial instrument settles. We also have maintenance margin deposits with certain counterparties in the OTC market. The payments on margin deposits occur when the value of a derivative exceeds our pre-established credit limit with the counterparty. Margin deposits are returned to us on the settlement date. We had net deposits with derivative counterparties of $87,806 and $65,034 as of August 31, 2006 and 2005, respectively, reflected as deposits paid to vendors on our consolidated balance sheets.

Allocation of Income (Loss)

For purposes of maintaining partner capital accounts, the Partnership Agreement of Energy Transfer Partners, L.P. (the Partnership Agreement) specifies that items of income and loss shall generally be allocated among the partners in accordance with their percentage interests (see Note 6). Normal allocations according to percentage interests are made after giving effect to any priority income allocations in an amount equal to the incentive distributions that are allocated 100% to the General Partner.

Recently Issued Accounting Standards

FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes - An Interpretation of FASB Statement No. 109*, (FIN 48). FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with SFAS No. 109. FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The new FASB standard also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. The evaluation of a tax position in accordance with FIN 48 is a two-step process. The first step is a recognition process whereby the enterprise determines whether it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. In evaluating whether a tax position has met the more-likely-than-not

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recognition threshold, the enterprise should presume that the position will be examined by the appropriate taxing authority that has full knowledge of all relevant information. The second step is a measurement process whereby a tax position that meets the more-likely-than-not recognition threshold is calculated to determine the amount of benefit to recognize in the financial statements. The tax position is measured at the largest amount of benefit that is greater than 50% likely of being realized upon ultimate settlement. The provisions of FIN 48 are effective for fiscal years beginning after December 15, 2006. Earlier application is permitted as long as the enterprise has not yet issued financial statements, including interim financial statements, in the period of adoption. The provisions of FIN 48 are to be applied to all tax positions upon initial adoption of this standard. Only tax positions that meet the more-likely-than-not recognition threshold at the effective date may be recognized or continue to be recognized upon adoption of FIN 48. The cumulative effect of applying the provisions of FIN 48 should be reported as an adjustment to the opening balance of retained earnings (or other appropriate components of equity or net assets in the statement of financial position) for that fiscal year. We are currently evaluating the statement and have not yet determined the impact of such on our financial statements.

SFAS No. 151*, Inventory Costs an amendment of ARB No. 43, Chapter 4* (SFAS 151). In November 2004, the FASB issued SFAS 151 which amends the guidance in ARB No. 43, Chapter 4, Inventory Pricing. ARB No. 43 previously required that certain costs associated with inventory be treated as current period charges if they were determined to be so abnormal as to warrant it. SFAS 151 amends this removing the so abnormal requirement and stating that unallocated overhead costs and other items such as abnormal handling costs and amounts of wasted materials (spoilage) require treatment as current period charges rather than a portion of inventory cost. SFAS 151 is effective for inventory costs incurred during fiscal years beginning after June 15, 2005, with earlier application permitted. The provisions of this statement need not be applied to immaterial items. We do not allocate overhead costs to inventory and management has determined that there are no other material items which require the application of SFAS 151.

SFAS No. 154*, Accounting Changes and Error Correction a replacement of APB Opinion No. 20 and FASB Statement No. 3* (SFAS 154). In May 2005, the FASB issued SFAS 154 which requires that the direct effect of voluntary changes in accounting principle be applied retrospectively with all prior period financial statements presented on the new accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. Indirect effects of a change should be recognized in the period of the change. SFAS 154 is effective for accounting changes and correction of errors made in fiscal years beginning after December 15, 2005. Management will adopt the provisions of SFAS 154 beginning September 1, 2006, as applicable. The impact of SFAS 154 will depend on the nature and extent of any voluntary accounting changes and correction of errors after the effective date, but management does not currently expect SFAS 154 to have a material impact on our consolidated results of operations, cash flows or financial position.

SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments An Amendment of FASB Statements No. 133 and 140* (SFAS 155). SFAS 155 is effective for all financial instruments acquired, issued, or subject to a remeasurement (new basis) event occurring after the beginning of an entity s first fiscal year that begins after September 15, 2006. Early application is permitted only if: (a) it occurs at the beginning of an entity s fiscal year and (b) the entity has not yet issued any interim or annual financial statements for that fiscal year. We intend to adopt this statement when required at the start of our fiscal year beginning September 1, 2008. The adoption of this statement is not expected to have a significant impact on us.

SFAS No. 157, *Fair Value Measurement,* (SFAS 157). This new standard provides guidance for using fair value to measure assets and liabilities. The FASB believes the standard also responds to investors requests for expanded information about the extent to which companies measure assets and liabilities at fair value, the information used to measure fair value, and the effect of fair value measurements on earnings. SFAS 157 applies whenever other standards require (or permit) assets or liabilities to be measured at fair value but does not expand the use of fair value in any new circumstances. The standard clarifies that for items that are not actively traded, such as certain kinds of derivatives, fair value should reflect the price in a transaction with a market participant, including an adjustment for risk, not just the company s mark-to-model value. SFAS 157 also requires expanded disclosure of the effect on earnings for items measured using unobservable data. Under SFAS 157, fair value refers to the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants in the market in which the reporting entity transacts. In this standard, the FASB clarifies the principle that fair value should be based on the assumptions market

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participants would use when pricing the asset or liability. In support of this principle, SFAS 157 establishes a fair value hierarchy that prioritizes the information used to develop those assumptions. The fair value hierarchy gives the highest priority to quoted prices in active markets and the lowest priority to unobservable data, for example, the reporting entity s own data. Under the standard, fair value measurements would be separately disclosed by level within the fair value hierarchy. The provisions of SFAS 157 are effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. Earlier application is encouraged, provided that the reporting entity has not yet issued financial statements for that fiscal year, including any financial statements for an interim period within that fiscal year. We are currently evaluating this statement and have not yet determined the impact of such on our financial statements. We plan to adopt this statement when required at the start of our fiscal year beginning September 1, 2008.

EITF Issue No. 04-13, *Accounting for Purchases and Sales of Inventory With the Same Counterparty* (EITF 04-13). In EITF 04-13, the Task Force reached a tentative conclusion that inventory purchases and sales transactions with the same counterparty that are entered into in contemplation of one another should be combined for purposes of applying Accounting Principles Board Opinion No. 29, Accounting for Nonmonetary Transactions. The tentative conclusions reached by the Task Force are required to be applied to transactions completed in reporting periods beginning after March 15, 2006. We adopted this EITF during fiscal year 2006 and such adoption did not have a material impact on our results of operations, financial position or cash flows.

EITF Issue No. 06-3, *How Taxes Collected from Customers and Remitted to Governmental Authorities Should be Presented in the Income Statement (that is, Gross Versus Net Presentation)* (EITF 06-3). This accounting guidance requires companies to disclose their policy regarding the presentation of tax receipts on the face of their income statements. The scope of this guidance includes any tax assessed by a governmental authority that is directly imposed on a revenue-producing transaction between a seller and a customer and may include, but is not limited to, sales, use, value added, and some excise taxes (gross receipts taxes are excluded). This guidance is effective for interim and annual reporting periods beginning after December 15, 2006 with earlier application permitted. As a matter of policy, we report such taxes on a net basis. We will adopt this EITF during our 2007 fiscal year.

4. NET INCOME PER LIMITED PARTNER UNIT:

Basic net income per limited partner unit is computed in accordance with EITF Issue No. 03-6, *Participating Securities and the Two-Class method under FASB Statement No. 128* (EITF 03-6), by dividing limited partners interest in net income by the weighted average number of Common and Class F Units outstanding. In periods when our aggregate net income exceeds the aggregate distributions, EITF 03-6 requires us to present

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earnings per unit as if all of the earnings for the periods were distributed (see table below) and requires a separate computation for each quarter and year-to-date. Diluted net income per limited partner unit is computed by dividing limited partners interest in net income, after considering the General Partner s interest, by the weighted average number of Common and Class F Units outstanding and the effect of non-vested restricted units (Unit Grants) granted under the 2004 Unit Plan and predecessor plan computed using the treasury stock method. A reconciliation of net income and weighted average units used in computing basic and diluted earnings per unit is as follows:

	Year Ended August 31, 2006	Year Ended August 31, 2005	Year Ended August 31, 2004
Net income	$ 515,852	$ 349,350	$ 99,152
Adjustments:			
General Partner s incentive distributions	(108,813)	(38,455)	(6,955)
General Partner s equity ownership	(10,172)	(6,987)	(1,983)
Limited Partner s interest in net income	$ 396,867	$ 303,908	$ 90,214
Additional earnings allocation to General Partner (a)	(48,781)	(49,462)	
Less earnings allocated to Class C Units as a result of the SCANA settlement (b)	(3,599)		
Net income available to limited partners (a)	$ 344,487	$ 254,446	$ 90,214
Weighted average limited partner units - basic	109,036,265	97,646,351	52,228,742
Limited Partners basic income per unit from continuing operations (a)	$ 3.16	$ 1.51	$ 1.62
Limited Partners basic income per unit from discontinued operations (a)		1.10	0.11
Basic net income per limited partner unit	$ 3.16	$ 2.61	$ 1.73
Weighted average limited partner units	109,036,265	97,646,351	52,228,742
Dilutive effect of Unit Grants	298,513	184,666	54,468
Weighted average limited partner units, assuming dilutive effect of Unit Grants	109,334,778	97,831,017	52,283,210
Limited Partners diluted income per unit from continuing operations (a)	$ 3.15	$ 1.50	$ 1.62
Limited Partners diluted income per unit from discontinued operations (a)		1.10	0.11
Diluted net income per limited partner unit	$ 3.15	$ 2.60	$ 1.73

(a) Basic and diluted net income per limited partner unit are determined based on the provisions of EITF 03-6. Our net income for partners capital and income statement presentation purposes is allocated to the General Partner and Limited Partners in accordance with their respective partnership percentages, after giving effect to priority income allocations for incentive distributions, if any, to our General Partner, the holder of the Incentive Distribution Rights pursuant to the Partnership Agreement, which are declared and paid following the close of each quarter. However, for purposes of computing basic and diluted net income per limited partner unit, in periods when our aggregate net income exceeds the aggregate distributions for such periods, an increased amount of net income is allocated to the General Partner for the additional pro forma priority income attributable to the application of EITF 03- 6. The General Partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in the Partnership Agreement. The basic and diluted earnings per limited partner unit from continuing operations and discontinued operations for the year ended August 31, 2005 differ from the amounts previously reported as a result of a change in methodology regarding the allocation of earnings between continuing operations and discontinued operations. Basic and diluted net income per limited partner unit did not change.

(b) As a result of the SCANA settlement discussed in Notes 6 and 9, we collected a settlement of $7,700 which is net of $3,300 of attorney fees. We retained $502 for litigation expenses previously incurred. The remaining $7,198 was allocated $3,599 to the Common and Class F Limited Partner Units and $3,599 as a special one-time distribution to the holder of our Class C Units for that amount normally allocated to our General Partner. The Limited Partner s share of available net income has been reduced accordingly.

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5. DEBT OBLIGATIONS:

Our debt obligations consist of the following:

	August 31, 2006	August 31, 2005	Maturities
Senior Notes:			
2005 5.95% Senior Notes, net of discount of $1,985 and $2,160, respectively.	$ 748,015	$ 747,840	One payment of $750,000 due February 1, 2015. Interest is paid semi-annually.
2005 5.65% Senior Notes, net of discount of $358 and $408, respectively.	399,642	399,592	One payment of $400,000 due August 1, 2012. Interest is paid semi-annually.
HOLP Senior Secured Notes:			
1996 8.55% Senior Secured Notes	60,000	72,000	Annual payments of $12,000 due each June 30th through 2011. Interest is paid semi-annually.
1997 Medium Term Note Program:			
7.17% Series A Senior Secured Notes	9,600	12,000	Annual payments of $2,400 due each November 19th through 2009. Interest is paid semi-annually.
7.26% Series B Senior Secured Notes	14,000	16,000	Annual payments of $2,000 due each November 19th through 2012. Interest is paid semi-annually.
6.50% Series C Senior Secured Notes	357	714	Annual payments of $357 due March 13, 2007. Interest is paid semi-annually.
2000 and 2001 Senior Secured Promissory Notes:			
8.47% Series A Senior Secured Notes	3,200	6,400	Annual payments of $3,200 due each August 15th through 2007. Interest is paid quarterly.
8.55% Series B Senior Secured Notes	18,286	22,857	Annual payments of $4,571 due each August 15th through 2010. Interest is paid quarterly.
8.59% Series C Senior Secured Notes	21,250	27,000	Annual payments of $5,750 due August 15, 2007, $4,000 due August 15, 2008, and $5,750 due each August 15, 2009 and 2010. Interest is paid quarterly.
8.67% Series D Senior Secured Notes	58,000	58,000	Annual payments of $12,450 due August 15, 2008 and 2009, $7,700 due August 15, 2010, $12,450 due August 15, 2011, and $12,950 due August 15, 2012. Interest is paid quarterly.
8.75% Series E Senior Secured Notes	7,000	7,000	Annual payments of $1,000 due each August 15, 2009 through 2015. Interest is paid quarterly.
8.87% Series F Senior Secured Notes	40,000	40,000	