Energy Transfer Partners, L.P.
Form 10-K
November 14, 2005
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended August 31, 2005

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 (State or other jurisdiction of incorporation or organization)	73-1493906 (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 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 x 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. ¨

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act). Yes x No ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ¨ No x

The aggregate market value as of February 28, 2005, 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 $1,976,900,000. 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 11, 2005, the registrant had units outstanding as follows:

Energy Transfer Partners, L.P. 106,894,514 Common Units

Documents Incorporated by Reference: None

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ENERGY TRANSFER PARTNERS, L.P.

2005 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 related 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 ex 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 7 of this annual report.

ITEM 1. BUSINESS.

Overview

We are a publicly traded master limited partnership that is primarily engaged in the natural gas midstream and transportation and storage business through our operating subsidiary, La Grange Acquisition, L.P. (ETC OLP), and we also have a national retail propane marketing business in the United States through our operating subsidiary, Heritage Operating, L.P (HOLP). As of September 30, 2005, we had an equity market capitalization of approximately $3.8 billion, making us the third largest publicly traded master limited partnership in equity market capitalization.

Our midstream, transportation and storage business owns and operates approximately 11,700 miles of natural gas gathering and transportation pipelines, 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. Through ETC OLP, we conduct our natural gas midstream, transportation and storage business through two segments, the midstream segment and the transportation and storage segment. Our midstream segment focuses on the gathering, compression, treating, 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 recently completed 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 the fourth largest retail propane marketer in the United States, serving more than 700,000 customers from 315 customer service locations in 34 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 a publicly traded Delaware limited partnership originally formed as Heritage Propane Partners, L.P. (Heritage), which consummated its initial public offering in June 1996. In January 2004, the propane operations of Heritage were combined with the natural gas midstream and transportation operations of La Grange Acquisition, L.P. conducted under the name Energy Transfer Company. We refer to this combination, along with the incurrence of debt and the issuance of equity securities of Heritage in connection with that combination, as the Energy Transfer Transactions . In March 2004, the combined entity s name was changed to Energy Transfer Partners, L.P. (the Partnership or ETP)

For the year ended August 31, 2005, we had revenues of approximately $6.2 billion, operating income of approximately $312.1 million and net income of approximately $349.4 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 3,742,515 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, 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 9,200,000 Common Units at an offering price of $38.69 per unit. The net proceeds were used to finance the Energy Transfer Transactions and for general partnership purposes.

Recent Acquisitions, Dispositions, and Expansion

Devon Midstream Assets Acquisition. On November 1, 2004, we announced the closing of the acquisition of certain midstream natural gas assets of Devon Energy Corporation for approximately $63.0 million in cash after adjustments. The assets, known as the Texas Chalk and Madison Systems, include approximately 1,800 miles of gathering and mainline pipeline systems, four natural gas treating plants, condensate stabilization facilities, fractionation facilities and the 80 MMcf/d Madison gas processing plant.

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Houston Pipeline System Acquisition. In January 2005, we acquired controlling interests in the Houston Pipeline System and related storage facilities from American Electric Power Corporation for approximately $825.0 million plus $132.0 million in natural gas inventory, subject to working capital adjustments. This transaction was financed by us through a combination of borrowings under our credit facilities and a private placement of $350.0 million of Common Units with institutional investors. In addition, we acquired working inventory of natural gas stored in the Bammel storage facility and financed it through a short-term borrowing from an affiliate. The total purchase price of approximately $825.0 million plus working capital, was allocated to the assets acquired and liabilities assumed. Under the terms of the transaction, we acquired all but a 2% limited partner interest in HPL Consolidation, L.P., the entity that owns the companies that own the Houston Pipeline System. The Houston Pipeline System is comprised of approximately 4,200 miles of intrastate pipeline with aggregate capacity of 2.4 Bcf/d, substantial storage facilities and related transportation assets.

Disposition of Elk City Gathering System. On April 14, 2005, we announced that we had closed the sale of our Oklahoma gathering, treating and processing assets, referred to as the Elk City system, to Atlas Pipeline Partners, L.P. The sale price of $191.6 million was used to repay a portion of the indebtedness incurred by us in our recent acquisition of the Houston Pipeline System and related storage facilities.

Fort Worth Basin Expansion. In May 2005, we completed construction of a 55-mile, 24-inch natural gas pipeline in the Fort Worth Basin that connects various pipelines in north Texas and provides transportation for natural gas production from the Barnett Shale producing area. This pipeline has a capacity in excess of 400 MMcf/d. The expansion cost approximately $53.0 million, which was financed entirely with cash from operations.

Recent Propane Acquisitions. During the fiscal year ended August 31, 2005, HOLP acquired substantially all of the assets of ten propane businesses. The aggregate purchase price for these acquisitions totaled $30.8 million.

Recent Expansion Projects. Our recently announced current construction projects are major expansion projects involving several pipeline projects that are expected to increase pipeline transportation access for natural gas producers in the Bossier Sands and Barnett Shale basins in east and north Texas to various markets throughout Texas as well as to markets in the eastern United States through interconnects with other intrastate and interstate pipelines. The larger of the two expansion projects involves the construction of approximately 264 miles of 42-inch pipeline and the addition of approximately 40,000 horsepower of compression at a cost of approximately $535.5 million. The 264 mile pipeline will extend from the intersection of the Fort Worth Basin and North Texas Pipeline near Cleburne, Texas to our Texoma pipeline and on to the Carthage, Texas market hub. This expansion project is supported by a 10-year agreement with XTO Energy, Inc. pursuant to which XTO Energy has agreed to transport specified volumes of natural gas on an annual basis and is entitled to transport additional volumes under similar terms. We expect this project to be completed by December, 2006, although segments of the project will become operational prior to that date. Our other major expansion project involves the construction, on a joint venture basis with Atmos Energy Corp., of a 30-inch pipeline in the north Fort Worth Basin area that will provide an additional outlet for natural gas from the Barnett Shale area to several market hubs. Our share of the estimated cost is approximately $29.3 million. These expansion projects will continue the integration of several pipeline systems and natural gas storage facilities, including the integration of our Katy Pipeline and our Southeast Texas System with the recently acquired ET Fuel System and Houston Pipeline System.

Loop of Fort Worth Basin Expansion. In addition, in response to additional activity in the Barnett Shale, we have approved the looping of the first 24 miles of our existing 55-mile, 24-inch pipeline in the Fort Worth Basin. The Fort Worth Basin Pipeline became commercially operational on May 26, 2005, at nearly full capacity. The looping of the first 24 miles of the system with another 24-inch pipeline and the addition of up to 12,000 horsepower of incremental compression will provide additional upstream capacities needed to accommodate the increased volumes in the Fort Worth Basin production area. The estimated cost to complete this project is approximately $32.1 million and is expected to be completed prior to the end of fiscal year 2006.

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Other Developments

On June 20, 2005, we completed a private sale of 1,640,000 of our Common Units to a group of our executive managers. The Common Units were sold at a price of $31.95 per Common Unit, reflecting a discount from the closing price on the last trading day of June 17, 2005. The price received was based on the fair market value and we believe is comparable to the price that we would have received from an unaffiliated purchaser in a large block equity transaction. The sale was approved by both the special committee of independent directors and the audit committee. The Common Units were issued pursuant to our effective shelf registration statement. Of the proceeds of approximately $52.1 million, $30.0 million was used to repay existing indebtedness and the balance was used for general partnership purposes.

On July 26, 2005, we completed a private sale of 3,000,000 of Common Units to an institutional investor. The Common Units were sold at a price of $35.20 per Common Unit. The Common Units were issued pursuant to our effective shelf registration statement. The proceeds of approximately $105.6 million were used to retire a portion of our outstanding indebtedness under our revolving credit facility and for general partnership purposes.

On July 29, 2005, we completed a registered exchange offer to exchange our 5.95% Senior Notes due February 1, 2015 issued in a Rule 144A private placement offering on January 18, 2005 (the 2015 Unregistered Notes), for a like amount of 5.95% Senior Notes due February 1, 2015 that are registered under the Securities Act of 1933, as amended.

On July 29, 2005, we completed a Rule 144A private placement offering of 5.65% Senior Notes due 2012 (the 2012 Unregistered Notes). The net proceeds of approximately $397.1 million were used to retire a portion of our outstanding indebtedness under our revolving credit facility, to fund our recently announced capital expansion projects and for general partnership purposes.

On November 10, 2005 the Partnership purchased the 2% limited partner interest in HPL that it did not already own, from AEP for $16.6 million in cash. As a result HPL became a wholly-owned subsidiary of ETC OLP.

ETC OLP

The operations of ETC OLP consist of the following:

Midstream and Transportation and Storage Operations. Our midstream and transportation and storage operations are primarily located in major natural gas producing regions of Texas. Our midstream and transportation and storage assets consist of our interests in approximately 11,700 miles of natural gas pipelines, three natural gas processing plants, two of which are connected to our gathering systems, 14 natural gas treating facilities and three natural gas storage facilities.

Our midstream segment consists of the following:

the Southeast Texas System, a 4,186-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 ten 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 Southeast Texas system includes the assets acquired from Devon in November 2004.

The La Grange and Madison processing plants are cryogenic natural gas processing plants that processes 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 ten treating facilities have an aggregate capacity of 740 MMcf/d. These treating facilities remove carbon dioxide and hydrogen sulfide from natural gas that is gathered into our system before the natural gas is introduced to transportation pipelines to ensure that the gas meets pipeline quality specifications.

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an interest in various midstream assets located in Texas and Louisiana, including the Vantex System, the Rusk County Gathering System, the Whiskey Bay System, the Dorado System and the Chalkley Transmission System. On a combined basis, these assets have a capacity of approximately 600 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 attracts 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 insights and valuable 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 is currently flowing west-to-east with a current average throughput of approximately 1.6 Bcf/d. 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 natural gas on the Southeast Texas System access 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 2,000 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 s current average throughput is approximately 1.1 MMcf/d. Prior to our acquisition of it in June 2004, the ET Fuel System had been operated primarily as a natural gas transmission pipeline system to supply natural gas from various natural gas producing areas to electric generating power plants of TXU Corp. and its affiliates, which we collectively referred to as TXU. In connection with our acquisition of the ET Fuel System, we entered into an eight-year transportation agreement with TXU Portfolio Management Company, LP, which we refer to as TXU Shipper, a subsidiary of

TXU, to transport a minimum of 115.6 MMBtu per year, subject to certain adjustments as defined in the agreement, and TXU Shipper has elected, effective January 1, 2006, to reduce the minimum amount of natural gas that

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we are obligated to transport to not less than 100.0 MMBtu per year. This is a one-time election allowed under the contract. We also entered into two eight-year natural gas storage agreements with TXU Shipper to store gas at two natural gas storage facilities that were part of the ET Fuel System. 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 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.

The East Texas Pipeline is a 148-mile natural gas pipeline that connects three treating facilities with our Southeast Texas System of which one treating facility is owned by us. This pipeline is the first phase of a multi-phased project that will service producers in East and North Central Texas providing 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 Counter Compressor Station. The capacity will increase to 720 MMcf/d in February 2006, with the addition of approximately 5,000 horsepower of electric compression. 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, 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. The Houston Pipeline System has a particularly strong presence in the key Houston Ship Channel and Katy Hub markets, which significantly contribute to the Houston Pipeline System s 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 its operation of the Bammel storage facility. The Bammel storage facility has a total working gas capacity of approximately 65 Bcf. The field 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.

The recently completed Fort Worth Basin Pipeline, which became operational on May 26, 2005, 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 Southeast Texas Pipeline assets with the ET Fuel System and the Houston Pipeline System.

Heritage Operating, L.P.

We believe we are the fourth largest retail propane marketer in the United States, serving more than 700,000 customers from 315 customer service locations in 34 states. Our 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.

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

	For the Years Ended August 31,		
	2003	2004	2005
Retail Gallons Sold (in millions):	375.9	397.9	406.3

Business Strategy

Our goal 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 and transportation and storage and propane businesses, we will be best positioned to achieve our objectives.

We expect that midstream and transportation and storage acquisitions, such as our recent acquisition of the ET Fuel System, the Devon midstream assets and the Houston Pipeline System, will be the primary focus of our acquisition strategy going forward, although we will also continue to pursue complementary propane acquisitions. 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.

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 expansion of existing systems, such as the East Texas Pipeline and the Fort Worth Basin project in North Texas, and construction of new facilities as discussed above. 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 exposure to changes in the prices of natural gas and NGLs. For example, we converted a contract with a major producer in the third fiscal quarter of 2005 from a commodity based contract to a fee-based contract.

Growth through acquisitions. As demonstrated by our recent acquisitions of the ET Fuel System, the Devon midstream assets and the Houston Pipeline System, 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 the additional acquisition opportunities likely to arise as a result of the ongoing divestiture of midstream assets by large industry participants.

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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 the fourth largest propane marketers 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 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 may 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 recently obtained credit facility and other recent financing transactions will 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 to 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.

Our assets provide marketing flexibility through our access to numerous markets and customers. Our Oasis Pipeline combined with the 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 enhanced our opportunities with additional power plants, industrial users, municipals, and co-operatives, and the added storage facilities add flexibility for fuel management services.

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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 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.

Our acquisition of 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 continuity and minimizing customer loss. We believe that this strategy has also helped to make it an attractive buyer for many propane acquisition candidates from the 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 the 2,642 full-time propane employees as of October 31, 2005, only 110, or approximately 4.2%, 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.

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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 a 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.

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, total domestic consumption of natural gas is expected to increase by over 2.2% per annum, on average, to 27.1 Tcf by 2010, from an estimated 22.2 Tcf consumed in 2001, representing approximately 25% of all total end-user energy requirements by 2010. During the last five years, the United States has on average consumed approximately 22.6 Tcf per year, with average domestic production of approximately 19.1 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 high 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.

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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 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. Based upon industry publications, propane accounts for six and one-half percent 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. 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 2005, our domestic wholesale operations (excluding M-P Energy Partnership) accounted for only 3.0% of our total gallons sold in the United States and approximately 1.2% 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

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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 various 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, 2005, we had one customer, BP Energy Company, that individually accounted for more than 10% of midstream and transportation and storage segment revenues. While this customer represents a significant percentage of midstream and transportation and storage segment revenues, the lost revenue from this customer would not have a material impact on our results of operations.

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. We do not own any 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.

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

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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.

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 are subject to change based on future determinations by FERC and the courts. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements and in some instances complaint-based rate regulation.

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

Sales of Natural Gas. 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

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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 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 it will be affected by any such FERC action materially differently than other natural gas marketers with whom it competes.

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 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 315 customer service locations in 34 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 700,000 active customers. Historically, approximately two-thirds of Heritage s retail propane volumes and in excess of 90% of its EBITDA, as adjusted, (please read footnote (c) under Item 6 Selected Historical Financial Data and Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations for a more detailed discussion of EBITDA, as adjusted) were 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 is loaded with propane from the storage tank. Propane is then delivered to the customer by the bobtail truck, which generally holds 2,500 to 3,000 gallons of propane, 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.

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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.

We own, through our subsidiaries, a 60% interest in M-P Energy Partnership, a Canadian partnership that supplies us with propane as described below under Propane Supply and Storage.

Approximately 97% of the domestic gallons we sold in the fiscal year ended August 31, 2005 were to retail customers and 3% were to wholesale customers. Of the retail gallons we sold, approximately 56% were to residential customers, 29% 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, 2004 accounted for 55% of total domestic gallons sold but accounted for approximately 69% 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 22% of our gross profit from propane sales for the fiscal year ended August 31, 2005, 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;
- 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, 2005 of approximately 89% 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

Supplies of propane from our sources historically have been readily available. 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, 2005, Enterprise Products Operating L.P. (Enterprise) and Dynegy Liquids Marketing and Trade (Dynegy) provided approximately 23.7% and 20.6% 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 in, procured 23.0% of our combined total propane supply during the fiscal year ended August 31, 2005. M-P Energy Partnership buys and sells propane for its own account and supplies propane to us for our northern United States operations.

We believe that if supplies from Enterprise and Dynegy were interrupted we would be able to secure adequate propane supplies from other sources without a material disruption of our operations. Aside from Enterprise,

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Dynegy 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, 2005. 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.

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 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 New York, Georgia, Michigan, Arizona, New Mexico, Texas, Alberta, Canada 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.

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, net losses or lower net income during the period from April through September of each year. Sales to industrial and agricultural customers are much less weather-sensitive.

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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.

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 as a result of such upsets, releases, or spills, including those relating to claims for damage to property and persons. 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

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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, 2005 an accrual of $2.0 million was recorded in our consolidated balance sheet to cover estimated environmental liabilities including certain matters assumed in connection with the HPL acquisition. We have also recorded a receivable of $0.4 million to account for the predecessor owner s share of certain environmental liabilities.

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.

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

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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 the cost of implementing these integrity management plans is $10 million per year, over the years 2006 to 2011.

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 hazard 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 31, 2005, we employ 551 people to operate our midstream and transportation and storage segments. We employ 2,642 full-time employees, of whom 54 are represented by labor unions to operate our propane segments. We believe that our relations with our employees are satisfactory. Historically, Heritage hires seasonal workers to meet peak winter demands in our propane operations.

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 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.

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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. We also lease office facilities in Houston, Texas, San Antonio, Texas, Tulsa, Oklahoma, and Helena, Montana. 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 are currently constructing new office facilities to replace our leased facility in Helena, Montana, which is for the administration of our propane operations.

We operate bulk storage facilities at over 315 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 33.0 million gallons of aboveground storage capacity at our various propane plant sites and have leased an aggregate of approximately 42.3 million gallons of underground storage facilities in New York, Georgia, Michigan, Arizona, New Mexico, Texas and Alberta, Canada. 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, 2005, we utilized approximately 50 transport truck tractors, 50 transport trailers, 16 railroad tank cars, 1,193 bobtails and 1,848 other delivery and service vehicles, all of which we own. As of August 31, 2005, we owned approximately 724,000 customer storage tanks with typical capacities of 120 to 1,000 gallons that are leased or available for lease to customers. These customer storage tanks are pledged as collateral to secure the obligations of HOLP to its banks and the holders of its notes.

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. 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, and V-1 Propane. 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.

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ITEM 3. LEGAL PROCEEDINGS.

Although our midstream operating partnership, ETC OLP, may, from time to time, be involved in litigation and claims arising out of its operations in the normal course of its business, ETC OLP is not currently a party to any material legal proceedings. In addition, we are not aware of any material legal or governmental proceedings against ETC OLP, or contemplated to be brought against ETC OLP, under the various environmental protection statutes to which it is subject.

At the time of the Houston Pipeline System acquisition, AEP Energy Services Gas Holding Company II, L.L.C., HPL Consolidation LP and its subsidiaries (the HPL Entities) and the parent companies of the HPL Entities were engaged in ongoing litigation with Bank of America that related to AEP s acquisition of the Houston Pipeline in the Enron bankruptcy and Bank of America s financing of cushion gas stored in the Bammel Storage facility (Cushion Gas). At issue are matters relating to the ownership and certain rights to use the Cushion Gas. We refer to this litigation 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.

Propane is a flammable, combustible gas. Serious personal injury and significant property damage can arise in connection with its storage, transportation or use. In the ordinary course of business, we are sometimes threatened with or are named as a defendant in various lawsuits seeking actual and punitive damages for product liability, personal injury and property damage. We maintain liability insurance with insurers in amounts and with coverages and deductibles we believe are reasonable and prudent, and which are generally accepted in the industry. However, there can be no assurance that the levels of insurance protection currently in effect will continue to be available at reasonable prices or that such levels will remain adequate to protect us from material expenses related to product liability, personal injury or property damage in the future. Although any litigation is inherently uncertain, based on past experience, the information currently available and the availability of insurance coverage, we do not believe that pending or threatened litigation matters will have a material adverse effect on our financial condition or results of operations.

Of the pending or threatened matters in which we or our subsidiaries are a party, none have arisen outside the ordinary course of our business except for an action filed by Heritage on November 30, 1999 against SCANA Corporation, Cornerstone Ventures, L.P. and Suburban Propane, L.P. in the Fifth Judicial Circuit Court of Common Pleas, Richland County, South Carolina (the SCANA litigation). In the SCANA litigation, Heritage sought to recover under various contract and fraud causes of action for damages incurred in connection with the 1999 breach of the agreement to sell SCANA s propane assets to Heritage. Prior to trial, a settlement was reached with Defendant Cornerstone Ventures, L.P. and they were dismissed from the litigation. The trial began on October 4, 2004 against the remaining defendants and testimony was concluded on October 20, 2004. On October 21, 2004, the jury returned a verdict in favor of Heritage against SCANA and in favor of defendant Suburban. The jury found in favor of Heritage on all four claims against SCANA, awarding a total of $48 million in actual and punitive damages. SCANA has appealed the jury s decision, and currently, the parties are involved in the appeal of a number of post-trial motions. We cannot predict whether the final judgment will affirm the jury verdict without any modification or whether any appeal of the final judgment by SCANA will be successful. As a result, we cannot yet predict whether we will receive any of the damages award covered by this verdict.

We are a party to various legal proceedings and/or regulatory proceedings incidental to our business. Certain claims, suits and complaints arising in the ordinary course of business have been filed or are pending against us. In the opinion of management, all such matters are either covered by insurance, are without merit or involve amounts, which, if resolved unfavorably, would not have a significant effect on our financial position or results of operations. 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, 2005, and 2004, accruals of $1.1 million and $0.9 million, respectively, were recorded as accrued

and other current liabilities on our consolidated balance sheets.

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

None

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		
	High	Low	Cash Distribution (1)
2005 Fiscal Year			
Fourth Quarter Ended August 31, 2005	$ 39.09	$ 31.69	$ 0.5000
Third Quarter Ended May 31, 2005	$ 33.13	$ 29.77	$ 0.48750
Second Quarter Ended February 29, 2005	$ 32.69	$ 25.80	$ 0.46250
First Quarter Ended November 30, 2004	$ 27.37	$ 21.51	$ 0.43750
2004 Fiscal Year			
Fourth Quarter Ended August 31, 2004	$ 21.69	$ 18.94	$ 0.41250
Third Quarter Ended May 31, 2004	$ 20.13	$ 17.25	$ 0.37500
Second Quarter Ended February 29, 2004	$ 21.33	$ 18.78	$ 0.35000
First Quarter Ended November 30, 2003	$ 19.35	$ 15.51	$ 0.32500

(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.

Description of Units

As of September 30, 2005, there were approximately 54,340 individual Common Unitholders, which includes Common Units held in Street name. Common Units and Class C Units represent limited partner interest in the Partnership s 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, 2005, we had 106,889,904 Common Units outstanding, of which 72,210,155 were held by the public, 32,773,840 were held by ETE or its affiliates, 1,308 were held by FHM Investments, L.L.C., and 1,904,601 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). Each holder of a Common Unit is entitled to one vote per unit on all matters presented to the limited partners for a vote. In addition, if at any time any person or group (other than our General Partner and its affiliates) owns beneficially 20% or more of all Common Units, any

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Common Units owned by that person or group may not be voted on any matter and are not considered to be outstanding when sending notices of a meeting of Unitholders (unless otherwise required by law), calculating required votes, determining the presence of a quorum or for other similar purposes under our Partnership Agreement. The Common Units are entitled to distributions of Available Cash as described below under Cash Distribution Policy.

Class C Units. As of August 31, 2005, we had 1,000,000 Class C Units outstanding, all of which are held by FHS Investments, L.L.C. The Class C Units were issued to the former owners of our former general partner, Heritage Holdings, in conjunction with the August 2000 transaction we refer to as the U.S. Propane Transaction. The Class C Units were created to convert that portion of the former general partner s incentive distribution rights that would have entitled it to receive any distributions attributable to certain litigation filed prior to the U.S. Propane Transaction. See Item 3 Legal Proceedings for a more detailed description of the SCANA litigation. The Class C Units do not have any rights to share in any of our assets or distributions upon dissolution and liquidation of ETP except to the extent that such distributions consists of proceeds from the SCANA litigation to which the Class C Unitholders would otherwise have been entitled; generally have no voting rights except to the extent provided by law, in which case they will be entitled to one vote; and are not convertible into any other unit.

When the special litigation committee decides to distribute the distributable proceeds, the amount of such distribution will be deemed to be Available Cash under our Partnership Agreement and will be distributed as described below under Cash Distribution Policy. The amount of distributable proceeds that would have otherwise been distributed to holders of Incentive Distribution Rights will instead be distributed to the holders of the Class C Units, pro rata. We cannot predict whether any cash payments will be received as a result of the SCANA litigation and, if so, when these distributions might be made. The amount of cash distributions to which the Incentive Distribution Rights are entitled was not increased by the creation of the Class C Units; rather, the Class C Units are a mechanism for dividing the Incentive Distribution Rights to which Heritage Holdings and its former stockholders would have been entitled had the litigation been resolved and funds received in connection with such resolution of that time.

Class D Units. The Class D Units were issued to ETE in the Energy Transfer Transactions. The Class D Units generally had voting rights identical to the voting rights of the Common Units, and the Class D Units voted with the Common Units as a single class on each matter with respect to which the Common Units were entitled to vote. Each Class D Unit initially was entitled to receive 100% of the quarterly amount distributed on each Common Unit, for each quarter, provided that the Class D Units were subordinated to the Common Units with respect to the payment of the minimum quarterly distribution for such quarter (and any arrearage in the payment of the minimum quarterly distribution for all prior quarters). 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. Holders of the Class D Units were entitled to vote upon the proposal to change the terms of the Class D Units and the Special Units in the same proportion as the votes cast by the holders of the Common Units (other than the Common Units issued to ETE in connection with the Energy Transfer Transactions) with respect to this proposal. 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. As of August 31, 2005, we had 8,853,832 Class E Units outstanding, all of which are held by our former general partner, Heritage Holdings. Heritage Holdings became our wholly-owned subsidiary in conjunction with the Energy Transfer Transactions. Class E Units were converted from Common Units held by Heritage Holdings at that time. Class E Units generally do not have voting rights; are entitled to aggregate distributions equal to a percentage of the total amount of cash distributed to all Unitholders, up to a maximum of $1.41 per Class E Unit per year; and will be allocated 1% of any gain and an equivalent amount of any loss allocated to the Common Units in the event of a termination or liquidation of ETP. Because the owner of the Class E Units is our wholly-owned subsidiary, those units are treated as treasury stock. Although distributions on the Class E Units will be available to us as the owner of Heritage Holdings, this amount will be reduced by the annual tax payments at corporate federal income tax rates that Heritage Holdings is required to pay with respect to distributions on the Class E Units.

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Special Units. The Special Units were issued to ETE in the Energy Transfer Transactions as consideration for the East Texas Pipeline. The Special Units generally did not have any voting rights but were entitled to vote on the proposal to change the terms of the Special Units in the same proportion as the votes cast by the holders of the Common Units (other than the Common Units issued to ETE in connection with the Energy Transfer Transactions) with respect to this proposal, and were not entitled to share in partnership distributions. We were required, as promptly as practicable following the issuance of the Special Units, to submit to a vote of our Unitholders the approval of the conversion of the Special Units into Common Units in accordance with the terms of the Special Units. 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.

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. The General Partner owns all of the Incentive Distribution Rights, except that in conjunction with the August 2000 U.S. Propane transaction we issued 1,000,000 Class C Units to Heritage Holdings, our general partner at that time, in conversion of that portion of Heritage Holdings Incentive Distribution Rights that entitled it to receive any distribution made by us of funds attributable to the net amount received in connection with the settlement, judgment, award or other final nonappealable resolution of the SCANA litigation.

Issuance of Additional Securities

Our Partnership Agreement authorizes us to issue an unlimited number of additional partnership securities and rights to buy partnership securities for the consideration and on the terms and conditions established by our General Partner in its sole discretion, without the approval of the Unitholders. Any such additional partnership securities may be senior to the Common Units.

It is possible that we will fund acquisitions through the issuance of additional Common Units or other equity securities. Holders of any additional Common Units we issue will be entitled to share equally with the then-existing holders of Common Units in our distributions of Available Cash. In addition, the issuance of additional partnership interests may dilute the value of the interests of the then-existing holders of Common Units in our net assets.

In accordance with Delaware law and the provisions of our Partnership Agreement, we may also issue additional partnership securities that, in the sole discretion of the General Partner, have special voting rights to which the Common Units are not entitled.

Upon issuance of additional partnership securities, our General Partner will be required to make additional capital contributions to the extent necessary to maintain its 2.0% General Partner interest in us. Moreover, our General Partner will have the right, which it may from time to time assign in whole or in part to any of its affiliates, to purchase Common Units or other equity securities whenever, and on the same terms that, we issue those securities to persons other than the General Partner and its affiliates, to the extent necessary to maintain its percentage interest, including its interest represented by Common Units, that existed immediately prior to each issuance. The holders of Common Units will not have preemptive rights to acquire additional Common Units or other partnership securities.

Amendments of our Partnership Agreement Requiring Unitholder Approval

The following matters require the approval of the majority of the outstanding Common Units, including the Common Units owned by the General Partner and its affiliates:

a merger of our Partnership;

a sale or exchange of all or substantially all of our assets;

dissolution or reconstitution of our Partnership upon dissolution;

certain amendments to the Partnership Agreement;

the transfer to another person of our General Partner interest before June 30, 2006 or the Incentive Distribution Rights at any time, except for transfers to affiliates of our General Partner or transfers in connection with the General Partner s merger or consolidation with or into, or sale of all or substantially all of its assets to, another person; and

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the withdrawal of the General Partner prior to June 30, 2006 in a manner that would cause the dissolution of our Partnership.

The removal of our General Partner requires the approval of not less than 66 2/3% of all outstanding units, including units held by our General Partner and its affiliates. Any removal is subject to the election of a successor General Partner by the holders of a majority of the outstanding Common Units, including units held by our General Partner and its affiliates.

Amendments to Our Partnership Agreement

Amendments to our Partnership Agreement may be proposed only by our General Partner. Certain amendments require the approval of a majority of the outstanding Common Units, including Common Units owned by the General Partner and its affiliates. Any amendment that materially and adversely affects the rights or preferences of any class of partnership interests in relation to other classes of partnership interests will require the approval of at least a majority of the class of partnership interests so affected. However, in some circumstances as more particularly described in our Partnership Agreement, our General Partner may make amendments to the Partnership Agreement without Unitholder approval to reflect, among other things:

a change in our name, the location of our principal place of business or our registered agent or office;

the admission, substitution, withdrawal or removal of partners;

a change to qualify or continue our qualification as a limited partnership or a partnership in which the limited partners have limited liability or to ensure that neither we nor our operating partnerships will be treated as an association taxable as a corporation or otherwise taxed as an entity for federal income tax purposes;

a change that does not affect our Unitholders in any material respect;

a change to (i) satisfy any requirements, conditions or guidelines contained in any opinion, directive, order, ruling or regulation of any federal or state agency or judicial authority or contained in any federal or state statute, (ii) facilitate the trading of Common Units or comply with any rule, regulation, guideline or requirement of any national securities exchange on which the Common Units are or will be listed for trading, (iii) that is necessary or advisable in connection with action taken by our General Partner with respect to subdivision and combination of our securities or (iv) that is required to effect the intent expressed in our Partnership Agreement;

a change in our fiscal year or taxable year and any changes that are necessary or advisable as a result of a change in our fiscal year or taxable year;

an amendment effected, necessitated or contemplated by a merger agreement approved in accordance with our Partnership Agreement;

an amendment that is necessary or advisable to reflect, account for and deal with appropriately our formation of, or investment in, any corporation, partnership, joint venture, limited liability company or other entity other than our Operating Partnerships, in connection with our conduct of activities permitted by our Partnership Agreement;

a merger or conveyance to effect a change in our legal form; or

any other amendment substantially similar to the foregoing.

Withdrawal or Removal of Our General Partner

Our General Partner has agreed not to withdraw voluntarily as our General Partner prior to June 30, 2006 without obtaining the approval of the holders of a majority of our outstanding Common Units, excluding those held by our General Partner and its affiliates, and furnishing an opinion of counsel stating that such withdrawal (following the selection of the successor general partner) would not result in the loss of the limited liability of any of our limited partners or of the limited partner of our operating partnership or cause us or our operating partnership to be treated as an association taxable as a corporation or otherwise to be taxed as an entity for federal income tax purposes (to the extent not previously treated as such).

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On or after June 30, 2006, our General Partner may withdraw as our General Partner without first obtaining approval of any Unitholder by giving 90 days written notice, and that withdrawal will not constitute a violation of our Partnership Agreement. In addition, our General Partner may withdraw without Unitholder approval upon 90 days notice to our limited partners if at least 50% of our outstanding Common Units are held or controlled by one person and its affiliates other than our General Partner and its affiliates.

Upon the voluntary withdrawal of our General Partner, the holders of a majority of our outstanding Common Units, excluding the Common Units held by the withdrawing general partner and its affiliates may elect a successor to the withdrawing general partner. If a successor is not elected, or is elected but an opinion of counsel regarding limited liability and tax matters cannot be obtained, we will be dissolved, wound up and liquidated, unless within 90 days after that withdrawal, the holders of a majority of our outstanding units, excluding the Common Units held by the withdrawing general partner and its affiliates, agree to continue our business and to appoint a successor general partner.

Our General Partner may not be removed unless that removal is approved by the vote of the holders of not less than two-thirds of our outstanding units, including units held by our General Partner and its affiliates, and we receive an opinion of counsel regarding limited liability and tax matters. In addition, if our General Partner is removed as our General Partner under circumstances where cause does not exist, our General Partner will have the right to receive cash in exchange for its partnership interest as a General Partner in us, its partnership interest as the General Partner of any member of the Energy Transfer partnership group and its incentive distribution rights. Cause is narrowly defined to mean that a court of competent jurisdiction has entered a final, non-appealable judgment finding the general partner liable for actual fraud, gross negligence or willful or wanton misconduct in its capacity as our General Partner. Any removal of this kind is also subject to the approval of a successor general partner by the vote of the holders of the majority of our outstanding Common Units, including those held by our General Partner and its affiliates.

While our Partnership Agreement limits the ability of our General Partner to withdraw, it allows the general partner interest to be transferred to an affiliate or to a third party in conjunction with a merger or sale of all or substantially all of the assets of our General Partner. In addition, our Partnership Agreement expressly permits the sale, in whole or in part, of the ownership of our General Partner. Our General Partner may also transfer, in whole or in part, any Common Units it owns.

Liquidation and Distribution of Proceeds

Upon our dissolution, unless we are reconstituted and continued as a new limited partnership, the person authorized to wind up our affairs (the liquidator) will, acting with all the powers of our General Partner that the liquidator deems necessary or desirable in its good faith judgment, liquidate our assets. The proceeds of the liquidation will be applied as follows:

first, towards the payment of all of our creditors and the creation of a reserve for contingent liabilities; and

then, to all partners in accordance with the positive balance in their respective capital accounts.

Under some circumstances and subject to some limitations, the liquidator may defer liquidation or distribution of our assets for a reasonable period of time. If the liquidator determines that a sale would be impractical or would cause a loss to our partners, our General Partner may distribute assets in kind to our partners.

Limited Call Right

If at any time less than 20% of the outstanding Common Units of any class are held by persons other than our General Partner and its affiliates, our General Partner will have the right to acquire all, but not less than all, of those Common 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. Our General Partner may assign this purchase right to any of its affiliates or us.

Indemnification

Under our Partnership Agreement, in most circumstances, we will indemnify our General Partner, its

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affiliates and their officers and directors to the fullest extent permitted by law, from and against all losses, claims or damages any of them may suffer by reason of their status as general partner, officer or director, as long as the person seeking indemnity acted in good faith and in a manner believed to be in or not opposed to our best interest. Any indemnification under these provisions will only be out of our assets. Our General Partner shall not be personally liable for, or have any obligation to contribute or loan funds or assets to us to effectuate any indemnification. We are authorized to purchase insurance against liabilities asserted against and expenses incurred by persons for our activities, regardless of whether we would have the power to indemnify the person against liabilities under our Partnership Agreement.

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.

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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.

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 and Class E 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 and Class E 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 and Class E 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 and Class E 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 and Class E 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

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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.

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 for the year ended August 31, 2005 on Common Units, Class E Units, General Partner interests and the Incentive Distribution Rights totaled $190.4 million, $12.5 million, $4.9 million, and $38.5 million, respectively. All such distributions were made from Available Cash from operating surplus.

Distributions of Cash Upon Liquidation

General. If we dissolve in accordance with our Partnership Agreement, we will sell or otherwise dispose of our assets in a process called liquidation. We will first apply the proceeds of liquidation to the payment of our creditors. We will distribute any remaining proceeds to our Unitholders and our General Partner, in accordance with their capital account balances, as adjusted to reflect any gain or loss upon the sale or other disposition of our assets in liquidation.

Any further net gain recognized upon liquidation will be allocated in a manner that takes into account the incentive distribution rights of our general partner.

Manner of Adjustments for Gain. The manner of the adjustment for gain is set forth in our Partnership Agreement in the following manner:

First, to our General Partner and the holders of our units who have negative balances in their capital accounts to the extent of and in proportion to those negative balances;

Second, 98% to our Common Unitholders, pro rata, and 2% to our General Partner, until the capital account for each Common Unit is equal to the sum of:

its unrecovered capital; and

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the amount of the minimum quarterly distribution for the quarter during which our liquidation occurs;

Third, 98% to all Unitholders, pro rata, and 2% to our General Partner, until we allocate under this paragraph an amount per unit equal to:

the sum of the excess of the first target cash distribution per unit over the minimum quarterly distribution per unit for each quarter of our existence; less

the cumulative amount per unit of any distributions of our available cash from operating surplus in excess of the minimum quarterly distribution per unit that we distributed 98% to our Unitholders, pro rata, and 2% to our General Partner, for each quarter of its existence;

Fourth, 85% to all Unitholders, pro rata, 13% to the holders of the incentive distribution rights, pro rata, and 2% to the General Partner, until we allocate under this paragraph an amount per unit equal to:

the sum of the excess of the second target cash distribution per unit over the first target cash distribution per unit for each quarter of our existence; less

the cumulative amount per unit of any distributions of our available cash from operating surplus in excess of the first target cash distribution per unit that it distributed 85% to the Unitholders, pro rata, 13% to the holders of the incentive distribution rights, pro rata, and 2% to our General Partner for each quarter of our existence;

Fifth, 75% to all Unitholders, pro rata, 23% to the holders of the incentive distribution rights, pro rata, and 2% to our General Partner, until we allocate under this paragraph an amount per unit equal to:

the sum of the excess of the third target cash distribution per unit over the second target cash distribution per unit for each quarter of our existence; less

the cumulative amount per unit of any distributions of our available cash from operating surplus in excess of the second target cash distribution per unit that it distributed 75% to the Unitholders, pro rata, 23% to the holders of the incentive distribution rights, pro rata, and 2% to our General Partner for each quarter of our existence; and

Sixth, thereafter, 50% to all Unitholders, pro rata, 48% to the holders of the incentive distribution rights pro rata, and 2% to our General Partner.

Manner of Adjustments for Losses. Upon our liquidation, we will generally allocate any loss to our General Partner and our unitholders in the following manner:

First, 98% to the holders of Common Units in proportion to the positive balances in their capital accounts and 2% to our General Partner, until the capital accounts of the Common Unitholders have been reduced to zero; and

Second, thereafter, 100% to our General Partner.

Adjustments to Capital Accounts upon the Issuance of Additional Units. We will make adjustments to our capital accounts upon issuance of additional units. In doing so, we will allocate any unrealized and, for tax purposes, unrecognized gain or loss resulting from the adjustments to our Unitholders and our General Partner in the same manner as it allocates gain or loss upon liquidation. In the event that we make positive adjustments to our capital accounts upon the issuance of additional units, we will allocate any later negative adjustments to our capital accounts resulting from our issuance of additional units or upon liquidation in a manner which results, to the extent possible, in our General Partner s capital account balances equaling the amount which they would have been if no earlier positive adjustments to its capital accounts had been made.

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Changes in Securities and Recent Sales of Unregistered Securities

None

Equity Compensation Plan Information

At the time of our initial public offering, the shareholders of our General Partner adopted a Restricted Unit Plan, amended and restated as of February 4, 2002 as the Partnership s Second Amended and Restated Restricted Unit Plan (the Restricted Unit Plan), which provided for the awarding of Common Units to key employees. See Executive Compensation Restricted Unit Plan for a description of the Restricted Unit Plan. At the June 23, 2004 special meeting of our Common Unitholders, Common Unitholders approved our 2004 Unit Plan, which provides for awards of Common Units and other rights to our employees, officers and directors and the Restricted Unit Plan was terminated except for our future obligation to issue Common Units that have not previously vested.

The following table sets forth in tabular format, a summary of our equity plan information:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders:			
Restricted Unit Plan	9,259	$ 315,732(1)	
2004 Unit Plan	276,835	9,440,074(1)	1,517,556
Equity compensation plans not approved by security holders:			
Total (2)	286,094	$ 9,755,806	1,517,556

(1) Valued as of October 31, 2005. Actual exercise price may differ depending on the Common Unit price on the date such units vest.
(2) As of August 31, 2005.

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, 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. Accordingly, ETC OLP s 11-month period ended August 31, 2003 is treated as a transition period.

ETC OLP s historical financial information for the period from October 1, 2002 to August 31, 2003 has been derived from the historical financial statements of ETC OLP included elsewhere in this report. During this time period, ETC OLP owned the Southeast Texas System and the Elk City System. From October 1, 2002 through December 27, 2002, ETC OLP also owned a 50% equity interest in Oasis Pipe Line Company, which owns the Oasis Pipeline. After December 27, 2002, ETC OLP owned a 100% interest in Oasis Pipe Line. In addition, on December 27, 2002, an affiliate of ETE s general partner contributed to ETC OLP its marketing business and its interest in the Vantex System, the Rusk County Gathering System, the Whiskey Bay System and the Chalkley Transmission System. 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 form October 1, 2002 to August 31, 2004 below have been restated to account for the results of the Elk City System in discontinued operations.

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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 on October 1, 2002.

The financial information below for Aquila Gas Pipeline for the nine months ended September 30, 2002 and the years ended December 31, 2001 and 2000 and as of September 30, 2002 and December 31, 2001 and 2000 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.

	Aquila Gas Pipeline			Energy Transfer Partners		
	Year Ended December 31,		Nine Months Ended September 30,	Eleven Months Ended August 31,	Year Ended August 31,	
	2000	2001	2002	2003(a)	2004	2005
Statement of Operating Data:						
Revenues						
Midstream segment	$ 1,758,530	$ 1,813,850	$ 933,099	$ 899,086	$ 1,880,663	$ 3,246,772
Transportation and storage segment				41,500	113,938	2,608,108
Eliminations				(9,559)	(27,798)	(471,255)
Propane segments					376,689	778,306
Other segment					3,465	6,867
Total revenues	1,758,530	1,813,850	933,099	931,027	2,346,957	6,168,798
Gross margin	117,663	98,589	53,035	105,589	365,533	787,283
Depreciation and amortization	30,049	30,779	22,915	11,870	48,599	92,943
Operating income	31,024	42,990	2,862	55,595	139,089	312,051
Interest expense	12,098	6,858	3,931	12,456	41,190	93,017
Income from continuing operations before income tax expense	18,892	41,161	4,272	45,063	97,470	208,678
Income tax expense (b)	7,657	15,403	(467)	4,432	4,481	7,295
Income from continuing operations	11,235	25,758	4,739	40,631	92,989	201,383
Basic income from continuing operations share/unit (c)				3.01	1.62	1.79
Cash distribution share/unit					1.47	1.89
Balance Sheet Data (at period end):						
Current assets	231,260	144,396	116,831	$ 223,897	480,435	1,458,020
Total assets	724,161	633,260	601,528	602,103	2,327,104	4,426,906
Current liabilities	313,506	194,816	144,076	169,473	397,037	1,250,874
Long-term debt	110,721	66,250	66,250	196,000	1,070,871	1,675,705
Stockholders equity/Partners capital	254,248	249,520	254,259	181,088	746,980	1,326,192
Other Financial Data:						
EBITDA, as adjusted (unaudited) (d)	61,039	78,798	31,118	77,476	196,650	413,237

Cash flow provided by operating activities	76,011	65,198	12,987	70,206	162,695	169,418
Cash flow used in investing activities	(23,459)	(20,727)	(487)	(341,258)	(790,737)	(1,133,749)
Cash flow provided by (used in) financing activities	(52,552)	(44,471)	(12,500)	324,174	656,665	907,500
Capital expenditures						
Maintenance and growth	26,866	23,944	5,486	11,914	109,688	196,459
Acquisition				340,187	681,835	1,131,844

(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 this date, Oasis Pipe Line s results of operations are consolidated with ETC OLP as a wholly-owned subsidiary.

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(b) As a partnership, we are not subject to income taxes. However, our subsidiaries, Oasis Pipe Line, Heritage Holdings and Heritage Service Corporation, 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) Net income per unit is computed by dividing the limited partners interest in net income by the weighted average number of units outstanding. For purposes of computing net income per limited partner unit, in periods when the Partnership s 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. Although the equity accounts of ETC OLP survive the Energy Transfer Transactions, Heritage s partnership structure and partnership units survive. Accordingly, the equity accounts of ETC OLP have been restated based on general partner interest and Common Units received by ETC OLP in the Energy Transfer Transactions.

(d) EBITDA, as adjusted, is defined as the Partnership s earnings before interest, taxes, depreciation, amortization and other non-cash items, such as compensation charges for unit issuances to employees, gain or loss on disposal of assets, and other expenses. We present EBITDA, as adjusted, on a Partnership basis, which includes both the general and limited partner interests. Non-cash compensation expense represents charges for the value of the Common Units awarded under the Partnership s compensation plans that have not yet vested under the terms of those plans and are charges which do not, or will not, require cash settlement. Non-cash income such as the gain arising from our disposal of assets is not included when determining EBITDA, as adjusted. EBITDA, as adjusted, (i) is not a measure of performance calculated in accordance with generally accepted accounting principles and (ii) should not be considered in isolation or as a substitute for net income, income from operations or cash flow as reflected in our consolidated financial statements.

EBITDA, as adjusted, is presented because such information is relevant and is used by management, industry analysts, investors, lenders and rating agencies to assess the financial performance and operating results of the Partnership s fundamental business activities. Management believes that the presentation of EBITDA, as adjusted, is useful to lenders and investors because of its use in the natural gas and propane industries and for master limited partnerships as an indicator of the strength and performance of the Partnership s ongoing business operations, including the ability to fund capital expenditures, service debt and pay distributions. Additionally, management believes that EBITDA, as adjusted, provides additional and useful information to the Partnership s investors for trending, analyzing and benchmarking the operating results of the Partnership from period to period as compared to other companies that may have different financing and capital structures. The presentation of EBITDA, as adjusted, allows investors to view the Partnership s performance in a manner similar to the methods used by management and provides additional insight to the Partnership s operating results.

EBITDA, as adjusted, is used by management to determine our operating performance, and along with other data as internal measures for setting annual operating budgets, assessing financial performance of the Partnership s numerous business locations, as a measure for evaluating targeted businesses for acquisition and as a measurement component of incentive compensation. The Partnership has a large number of business locations located in different regions of the United States. EBITDA, as adjusted, can be a meaningful measure of financial performance because it excludes factors which are outside the control of the employees responsible for operating and managing the business locations, and provides information management can use to evaluate the performance of the business locations, or the region where they are located, and the employees responsible for operating them. Our EBITDA, as adjusted, includes non-cash compensation expense which is a non-cash expense item resulting from our unit based compensation plans that does not require cash settlement and is not considered during management s assessment of the operating results of the Partnership s business. By adding these non-cash compensation expenses in EBITDA, as adjusted, allows management to compare the Partnership s operating results to those of other companies in the same industry who may have compensation plans with levels and values of annual grants that are different than the Partnership s. Other expenses include other finance charges and other asset non-cash impairment charges that are reflected in the Partnership s operating results but are not classified in interest, depreciation and amortization. We do not include gain on the sale of assets when determining EBITDA, as adjusted, since including non-cash income resulting from the sale of assets increases the

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performance measure in a manner that is not related to the true operating results of the Partnership s business. In addition, our debt agreements contain financial covenants based on EBITDA, as adjusted. For a description of these covenants, please read Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations-Description of Indebtedness.

There are material limitations to using a measure such as EBITDA, as adjusted, including the difficulty associated with using it as the sole measure to compare the results of one company to another, and the inability to analyze certain significant items that directly affect a company s net income or loss. In addition, our calculation of EBITDA, as adjusted, may not be consistent with similarly titled measures of other companies and should be viewed in conjunction with measurements that are computed in accordance with GAAP. EBITDA, as adjusted, for the periods described herein is calculated in the same manner as presented by us in the past. Management compensates for these limitations by considering EBITDA, as adjusted, in conjunction with its analysis of other GAAP financial measures, such as gross profit, net income (loss), and cash flow from operating activities. A reconciliation of EBITDA, as adjusted, to net income (loss) is presented below. Please read Reconciliation of EBITDA, As Adjusted, to Net Income below.

Reconciliation of EBITDA, As Adjusted, to Net Income

The following tables set forth the reconciliation of EBITDA, as adjusted, to net income for the periods indicated:

	Aquila Gas Pipeline			Energy Transfer Partners		
	Year Ended August 31, 2000	Year Ended August 31, 2001	Nine Months Ended September 30, 2002	Eleven Months Ended August 31 2003	Year Ended August 31, 2004	Year Ended August 31, 2005
Net income reconciliation						
Net income	$ 11,235	$ 25,758	$ 4,739	$ 46,625	$ 99,152	$ 349,350
Gain on sale of discontinued operations, net of income tax expense						(142,469)
Depreciation and amortization	30,049	30,779	22,915	11,870	48,599	92,943
Interest	12,098	6,858	3,931	12,456	41,190	93,017
Income tax expense on continuing operations	7,657	15,403	(467)	4,432	4,481	7,295
Non-cash compensation expense					42	1,608
Other, net				(501)	(509)	(631)
Depreciation, amortization, and interest and taxes of investee				1,003	440	697
Depreciation, amortization and interest of discontinued operations				1,591	2,249	1,547
Loss on extinguishment of debt						9,550
Loss on disposal of assets					1,006	330
EBITDA, as adjusted (a)	$ 61,039	$ 78,798	$ 31,118	$ 77,476	$ 196,650	$ 413,237

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ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

Overview

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

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, and HOLP, a Delaware limited partnership (the Operating Partnerships). The Partnership and the Operating Partnerships are sometimes referred to collectively in this report as 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 intrastate natural gas midstream business (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 its existing infrastructure and acquiring certain additional businesses or assets.

Factors That Significantly Affect our Results. The actual amount of cash that we will have available for distribution will primarily depend on the amount of cash we generate from operations.

We have grown significantly through acquisitions and through internal growth projects. The significant acquisitions and internal construction projects that we have completed beginning in January 2004 include:

Energy Transfer Transactions. In January 2004, in a series of related transactions, the midstream and transportation operations of La Grange Acquisition, L.P. were combined with the retail propane operations of Heritage Propane Partners, L.P., a publicly traded limited partnership. These transactions, which we refer to as the Energy Transfer Transactions, were valued at approximately $1.0 billion and created ETP. Subsequent to these transactions, the combined partnership s name was changed to Energy Transfer Partners, L.P.

ET Fuel System. In June 2004, we acquired the midstream natural gas assets of TXU Fuel Company (now referred to as the ET Fuel System) from TXU Corp. for approximately $500 million. The ET Fuel System is comprised of approximately 2,000 miles of intrastate natural gas pipelines and related natural gas storage facilities that serve some of the most active natural gas drilling areas in Texas and provide direct access to power plants and interconnects with other intrastate and interstate pipelines that serve major markets.

East Texas Pipeline. In June 2004, we completed the construction of the Bossier Pipeline (now referred to as the East Texas Pipeline). The East Texas Pipeline is a 78-mile natural gas pipeline that provides transportation from the Bossier Sands drilling area in east and north central Texas to our Southeast Texas System. This pipeline cost approximately $71.4 million to construct.

Texas Chalk and Madison Systems. In November 2004, we acquired the Texas Chalk and Madison Systems from Devon Energy Corporation for approximately $65.0 million. These systems consist of approximately 1,800 miles of gathering and mainline pipelines, four natural gas treating facilities and a natural gas processing facility located in central Texas near our existing gathering and processing assets.

Houston Pipeline System. In January 2005, we acquired the Houston Pipeline System from American Electric Power Company, Inc. for approximately $825.0 million plus $132.0 million in natural gas inventory, subject to working capital adjustments. This system is comprised of six main transportation pipelines, three market area loops and a natural gas storage facility in Texas.

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Fort Worth Basin. In May 2005, we completed the construction of the Fort Worth Basin Pipeline, a 55-mile pipeline that provides transportation for natural gas production from the Barnett Shale producing area in north central Texas to ETP s North Texas Pipeline. This pipeline cost approximately $53.0 million to construct.

Our 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 our 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 we earn 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. The terms of our contracts vary based upon gas quality conditions, the competitive environment at the time the contracts are signed and customer requirements. Many of these contracts remain in effect for several years. The 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. For additional information related to factors that affect the results of our midstream segment, please read Overview of Operations Midstream and Transportation and Storage Segments below.

Results from our transportation and storage segment are determined primarily by the amount of capacity our customers reserve as well as the actual volume of natural gas that flows through our transportation pipelines. Under transportation contracts, we charge our customers (1) 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, (2) a transportation fee, which is based on the actual throughput of natural gas by the customer, or (3) a fuel retention based on a percentage of gas transported on the pipeline, or a combination of the three, generally payable monthly. We also generate revenue 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.

The transportation and storage segment also generates its 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 Houston Pipeline System. Generally, HPL purchases its natural gas from either the market including purchases from the midstream 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. For additional information related to factors that affect the results of our transportation and storage segment, please read Overview of Operations Midstream and Transportation and Storage Segments below.

Our propane-related 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 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 storage significant volumes of propane 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, for future resale. In particular, our propane distribution business is largely seasonal and dependent upon weather conditions in our service areas. For additional information related to factors that affect the results of our propane-related segments, please read Overview of Operations Retail and Wholesale Propane Segments below.

None of our operations suffered any material damage or interruption from either Hurricane Katrina or Hurricane Rita, which landed in Louisiana and Texas, respectively, during September 2005.

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Trends and Outlook

We expect our business to continue to be affected by the following key trends. Our expectations are based on assumptions made by us and information currently available to us. To the extent our underlying assumptions about or interpretations of available information prove to be incorrect, our actual results may vary materially from our expected results.

We believe that current natural gas prices will continue to cause relatively high levels of natural gas-related drilling in the United States as producers seek to increase their level of natural gas production. Although the number of natural gas wells drilled in the United States has increased overall in recent years, a corresponding increase in average annual production has not been realized, primarily as a result of smaller average discoveries and the decline in production from existing wells. We believe that an increase in United States drilling activity and imports of natural gas and liquefied natural gas will be required for the natural gas industry to meet the expected increased demand for, and to compensate for the declining production of, natural gas in the United States. A number of the areas in which we operate are experiencing significant drilling activity as a result of recent high natural gas prices, new increased drilling for deeper natural gas formations and the implementation of new exploration and production techniques.

While we anticipate continued high levels of exploration and production activities in a number of the areas in which we operate, fluctuations in energy prices can greatly affect production rates and investments by third parties in the development of new natural gas reserves. Drilling activity generally decreases as natural gas prices decrease. We have no control over the level of drilling activity in the areas of our operations.

The midstream natural gas industry is cyclical, with the operating results of companies in the industry significantly affected by the prevailing price of NGLs, which in turn has been generally correlated to the price of crude oil. Although the prevailing price of natural gas has less short term significance to our operating results than the price of NGLs, in the long term, the growth and sustainability of our business depends on natural gas prices being at levels sufficient to provide incentives and capital for producers to increase natural gas exploration and production. In the past, the prices of NGLs, crude oil and natural gas have been extremely volatile.

Based on historical trends, we generally expect NGL prices to follow changes in crude oil prices over the long term, which we believe will in large part be determined by the level of production from major crude oil exporting countries and the demand generated by growth in the world economy. We believe that future natural gas prices will be influenced by supply deliverability, the severity of winter and summer weather and the level of worldwide economic growth. The number of active oil and gas rigs drilling in the United States were 223 and 1,219, respectively at August 31, 2005, compared to 166 and 1,082, respectively, at August 31, 2004. The increase in natural gas rigs is primarily attributable to recent significant increases in natural gas prices, which could result in continued sustained drilling activity for the remainder of 2005.

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the eleven-month period ended August 31, 2003 or the years ended August 31, 2004 and 2005. It may in the future, however, increase the cost to acquire or replace property, plant and equipment and may increase the costs of labor and supplies. To the extent permitted by competition, regulation and our existing agreements, we have and will continue to pass along increased costs to our customers in the form of higher fees.

Risk Factors

An investment in our common units involves risks. If any of these risks were to occur, our business, financial condition or results of operations could be materially adversely affected. In that case, the trading price of our common units could decline, and you could lose all or part of your investment. Among the key risk factors that may have a direct bearing on our results of operations and financial condition are:

- **the general economic conditions in the United States of America as well as the general economic conditions and currencies in foreign countries;**

- **the amount of natural gas transported on our pipelines and gathering systems;**

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- **the level and throughput in our natural gas processing and treating facilities;**
- **the fees ETC OLP charges and the margins realized for its services;**
- **the prices and market demand for, and the relationship between, natural gas and NGLs;**
- **energy prices generally;**
- **the price of propane to the consumer compared to the price of alternative and competing fuels;**
- **the general level of petroleum product demand and the availability and price of propane supplies;**
- **the level of domestic oil and natural gas production;**
- **the availability of imported oil and natural gas;**
- **the ability to obtain adequate supplies of propane for retail sale in the event of an interruption in supply or transportation and the availability of capacity to transport propane to market areas;**
- **actions taken by foreign oil and gas producing nations;**
- **the political and economic stability of petroleum producing nations;**
- **the effect of weather conditions on demand for oil, natural gas and propane;**
- **the weather in our operating areas;**
- **availability of local, intrastate and interstate transportation systems;**
- **the continued ability to find and contract for new sources of natural gas supply;**
- **availability and marketing of competitive fuels;**
- **the impact of energy conservation efforts;**
- **energy efficiencies and technological trends;**

the extent of governmental regulation and taxation;

hazards or operating risks incidental to the transporting, treating and processing of natural gas and NGLs or to the transporting, storing and distributing of propane that may not be fully covered by insurance;

the maturity of the propane industry and competition from other propane distributors;

competition from other midstream companies;

management has limited discretion under Board guidelines in conducting our risk management activities and may not accurately predict future price fluctuations and therefore expose us to financial risks and reduce our opportunity to benefit from price fluctuations;

changes in commodity prices may subject us to margin calls, which may adversely affect our liquidity;

loss of key personnel;

loss of key natural gas producers or the providers of fractionation services;

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reductions in the capacity or allocations of third party pipelines that connect with Energy Transfer s pipelines and facilities;

the effectiveness of risk-management policies and procedures and the ability of our marketing counterparties to satisfy their financial commitments and the nonpayment or nonperformance by our customers;

the availability and cost of capital and our ability to access certain capital sources;

changes in laws and regulations to which we are subject, including tax, environmental, transportation and employment regulations;

the costs and effects of legal and administrative proceedings;

the ability to successfully identify and consummate strategic acquisitions at purchase prices that are accretive to our financial results; and

risks associated with the construction of new pipelines and treating and processing facilities or additions to our existing pipelines and facilities.

You should not put undue reliance on any forward-looking statements. When considering forward-looking statements, please review the risk factors described above.

Energy Transfer Transactions

On January 20, 2004, Heritage and ETE completed the 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 3,742,515 Special Units as consideration for the project it had in progress to construct 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 Energy Transfer s 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 interest in ETP GP, the General Partner of Heritage, and ETP GP s general partner, ETP LLC, from subsidiaries of AGL Resources, 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 through the sale of 9,200,000 Common Units at an offering price of $38.69 per unit. The net proceeds were used to finance the Energy Transfer Transactions and for general partnership purposes.

The Energy Transfer Transactions 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 acquiror for accounting purposes. As a result, ETC OLP s historical financial statements will be the historical financial statements of the registrant. The operations of Heritage prior to the Energy Transfer Transactions are referred to as Heritage.

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Other Recent Transactions

On October 17, 2005, we announced that the Board of Directors of our General Partner approved two new pipeline construction projects. The first project involves the expansion of our previously announced 264-mile intrastate pipeline project by increasing the pipeline s size to 42-inch for a larger portion of the project. The second project involves the construction of a new pipeline which will loop 24 miles of our existing 24-inch pipeline in the Fort Worth Basin production area.

These two recently announced major expansion projects involve several pipeline projects that are expected to increase pipeline transportation access for natural gas producers in the Bossier Sands and Barnett Shale basins in east and north Texas to various markets throughout Texas as well as to markets in the eastern United States through interconnects with other intrastate and interstate pipelines. The larger of the two expansion projects involves the construction of approximately 264 miles of 42-inch pipeline and the addition of approximately 40,000 horsepower of compression at a cost of approximately $535.5 million. The 264 mile pipeline will extend from the intersection of Fort Worth Basin and North Texas Pipeline near Cleburne, Texas to our Texoma pipeline and on to the Carthage, Texas market hub. This expansion project is supported by a 10-year agreement with XTO Energy, Inc. in which XTO Energy has agreed to transport specified volumes of natural gas on an annual basis and is entitled to transport additional volumes under similar terms. We expect this project to be completed by December 2006, although segments of the project will become operational prior to that date. Our other major expansion project involves the construction, on a joint venture basis with Atmos Energy Corp., of a 30-inch pipeline in the north Fort Worth Basin area that will provide an additional outlet for natural gas from the Barnett Shale area to several market hubs at a cost of approximately $29.3 million. These expansion projects will continue the integration of several pipeline systems and natural gas storage facilities, including the integration of our Katy Pipeline and Southeast Texas System with the recently acquired ET Fuel System and Houston Pipeline System. We expect this project to be completed in February 2006.

In addition, in response to additional activity in the Barnett Shale, we have approved the looping of the first 24 miles of our existing 55-mile, 24-inch pipeline in the Fort Worth Basin. The Fort Worth Basin Pipeline became commercially operational on May 26, 2005, at nearly full capacity. The looping of the first 24 miles of the system with another 24-inch pipeline and the addition of up to 12,000 horsepower of incremental compression will provide additional upstream capacities needed to accommodate the increased volumes in the Fort Worth Basin production area. The estimated cost to complete this project is approximately $32.1 million and is expected to be completed prior to the end of fiscal year 2006.

On November 10, 2005 the Partnership purchased the remaining 2% limited partner interest in HPL from AEP for $16.6 million in cash. As a result the Partnership now owns 100% of the general and limited interests in HPL.

Overview of Operations

Midstream and transportation and storage segments

Our midstream and transportation and storage segments are operated by ETC OLP. We own and operate approximately 11,700 miles of natural gas gathering and transportation pipelines, 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. Our midstream segment focuses on the transportation, gathering, compression, treating, processing and marketing of natural gas. 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 through the Oasis Pipeline, our East Texas Pipeline, our natural gas pipeline and storage assets that are referred to as the ET Fuel System, and certain transportation assets of the recently acquired HPL System. The Oasis Pipeline is a

583-mile natural gas pipeline that directly connects the Waha Hub, a major natural gas trading center located in the Permian Basin of west Texas, to the Katy Hub, a major natural gas trading center near Houston, Texas. The East Texas Pipeline connects natural gas supplies in east Texas to the Katy Pipeline. The ET Fuel System, which serves some of the most active drilling areas in the United States, is comprised of approximately 2,000 miles of intrastate natural gas pipeline and related natural gas storage facilities located in Texas. With approximately 460 receipt and/or delivery

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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 major markets such as the Waha Hub, the Katy Hub and the Carthage Hub, three major natural gas trading centers located in Texas. Our transportation and storage segment also includes the recently acquired HPL System which is comprised of approximately 4,200 miles of intrastate natural gas pipeline, 65 Bcf of working gas underground Bammel storage reservoir and related transportation assets. The HPL System has access to multiple sources of historically significant natural gas supply reserves from south Texas, the Gulf Coast, 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, Baytown, Beaumont and Port Arthur. The HPL System consists of six main transportation pipelines and three market area loops and has direct access to multiple market hubs at Katy, the Houston Ship Channel, Ague Dulce and through its operations of the Bammel storage facility.

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 our midstream gross margins under fee-based or other arrangements. Under fee-based arrangements, we receive a fee for natural gas gathering, compressing, treating or processing services. The revenue we earn 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 the 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 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 upon gas quality conditions, the competitive environment at the time the contracts are signed and customer requirements. The 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, which we refer to as on-system gas. We also attract other customers by marketing volumes of natural gas that do not move through our assets, which we refer 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.

During the fourth quarter of the year ended August 31, 2005, we adopted a new risk management policy that provides for our marketing operations to execute limited strategies. Certain strategies are considered trading activities for accounting purposes and are accounted for in net revenues on the consolidated statement of operations. Our trading activities include purchasing and selling natural gas and the use of financial instruments, including NYMEX futures contracts, basis contracts and gas daily contracts. See further discussion regarding our risk management policies in Item 7a. Quantitative and Qualitative Disclosures about Market Risk found elsewhere in this report.

Results from our transportation and storage segment are determined primarily by the amount of capacity our customers reserve as well as the actual volume of natural gas that flows through our transportation pipelines. Under transportation contracts, we charge our customers (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, and (iii) a fuel retention based on a percentage of gas transported on the pipeline, or a combination of the three, generally payable monthly. We also generate revenue 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.

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The transportation and storage segment also generates its 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 the midstream 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.

As a result of our acquisition of the HPL System, we now 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. The Bammel storage reservoir is one of the largest storage facilities in North America with 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 HPL System has engineered an injection well configuration to provide for a 0.6 Bcf/d peak injection rate. Therefore, 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, we have continually managed our positions to enhance the future profitability of our storage position. We may, from time to time, change our scheduled injection and withdrawal plans based on market conditions and adjust the level of working natural gas stored in the Bammel reservoir. 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. As of August 31, 2005, we had approximately 28 Bcf of working natural gas stored in the Bammel storage facility. We intend to continue to purchase and store natural gas in our first quarter of 2006 in order to meet anticipated demand during the periods from November to March. However, we can not 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.

Retail and Wholesale Propane segments

Our propane-related segments are operated by HOLP and its subsidiaries who are engaged in the sale, distribution and marketing of propane and other related products through its retail and wholesale segments, (the propane segments). HOLP derives its revenue primarily from the retail propane segment. We believe that we are the fourth largest retail marketer of propane in the United States, based on retail gallons sold. We serve more than 700,000 propane customers from 315 customer service locations in 34 states.

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 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 storage significant volumes of propane 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, for future resale.

Our retail propane business consists principally of transporting propane purchased in the contract and spot markets, primarily from major fuel suppliers, to our customer service locations and then to propane tanks located on the customers premises, as well as to portable propane cylinders. In the residential and commercial markets, propane is primarily used for space heating, water heating, and cooking. In the agricultural market, propane is primarily used for crop drying, tobacco curing, poultry brooding, and weed control. In addition, propane is used for certain industrial applications, including use as an engine fuel to power vehicles and forklifts and as a heating source in manufacturing and mining processes.

Our propane distribution business is largely seasonal and dependent upon weather conditions in our service areas. Propane sales to residential and commercial customers are affected by winter heating season requirements. Historically, approximately two-thirds of HOLP s retail propane volume and in excess of 80% of HOLP s EBITDA, as adjusted, 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

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the period from April through September of each year. Consequently, sales and operating profits for the propane segments are concentrated in the first and second fiscal quarters, however, cash flow from operations is generally greatest during the 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 realized in our areas of operations, particularly during the six-month peak-heating season, to have a significant effect on the financial performance in 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 on normal temperatures in understanding 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. Because MP Energy Partnership is primarily engaged in lower-margin wholesale distribution, its contribution to our net income is not significant, and the minority interest of this partnership is excluded from the EBITDA, as adjusted, calculation.

Analysis of Historical Results of Operations

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.

In addition to the Energy Transfer Transactions, the acquisition of the ET Fuel System affects the comparability of the historical results of operations in our transportation and storage segment for the year ended August 31, 2005 compared to the year ended August 31, 2004. We acquired the ET Fuel System in June 2004; therefore, the results of operations for the year ended August 31, 2004 do not reflect the impact of this acquisition for a full year. We also acquired the HPL System in January 2005. The acquisition of HPL affects the comparability of the historical results of operations in our transportation and storage operating segment for the year ended August 31, 2005 compared to the year ended August 31, 2004. The results of operations for the year ended August 31, 2004 do not reflect the impact of this acquisition and the results of operations for the year ended August 31, 2005 only include the results of operations of HPL from the date of acquisition to August 31, 2005.

In addition, we completed the sale of our Oklahoma gathering, treating and processing assets, referred to as the Elk City System, on April 14, 2005. These results are presented as net amounts in the Consolidated Statements of Operations, with prior periods restated to conform to the

current presentation. Selected operating results for the midstream segment discussed below have been restated for the periods presented to reflect the discontinued operations.

Overall Increase in Results of Operations. We have experienced a significant increase in our results of operations for year ended August 31, 2005 when compared to last year. The increase is principally attributable to the following:

Energy Transfer Transactions noted above. The transactions were accounted for as a reverse acquisition and ETC OLP had no propane operations prior to the transaction;

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Acquisitions. We have been successful in completing various strategic acquisitions during the last twelve to eighteen months by both of our operating partnerships, ETC OLP and HOLP. As discussed above, we completed the acquisition of the ET Fuel System in June 2004 and the HPL System in January 2005. We also acquired the Texas Chalk and Madison System in November 2004. These acquisitions have significantly increased our asset base and operations for the 2005 periods presented. In addition, HOLP has made a number of propane acquisitions during the periods presented;

Completion of the East Texas Pipeline. We completed the East Texas Pipeline in June 2004. As a result, the 2004 period only contains the results of operations from June 2004 to August 2004, compared to a full year of operations for the 2005 period.

Increased volumes and prices. In addition to the acquisitions, we have also experienced increased volumes in our existing operating segments as a result of various strategies put in place by management. Commodity prices have also increased resulting in increased revenues and costs of sales, primarily in our midstream segment.

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

Volume. The following table presents selected volumetric information related to our operating segments for the years ended August 31, 2005 and 2004:

	August 31, 2005 (Actual)	August 31, 2004 (Actual)
Midstream		
Natural gas MMBtu/d sold	1,694,573	1,026,773
NGLs Bbls/d - sold	12,707	6,920
Transportation and storage		
Natural gas MMBtu/d - sold	1,361,729	
Natural gas MMBtu/d - transported	3,495,434	1,090,710
NGLs Bbls/d - sold	1,735	

Midstream. Natural gas sales volumes were 1,694,573 MMBtu/d for the year ended August 31, 2005 compared to 1,026,773 MMBtu/d for the year ended August 31, 2004, an increase of 667,800 MMBtu/d. NGLs sales volumes were 12,707 Bbls/d and 6,920 Bbls/d for the year ended August 31, 2005 and August 31, 2004, respectively. 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. Our sales volumes of NGLs 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. Transportation natural gas volumes increased by 2,404,724 MMBtu/d from 1,090,710 MMBtu/d for the year ended August 31, 2004 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 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.

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	Year Ended		
	August 31, 2005	August 31, 2004	August 31, 2004
	(Actual)	(Actual)	(Aggregate)
Propane gallons (in thousands)			
Retail	406,334	226,209	397,862
Wholesale	70,047	35,719	64,399

Retail Propane. 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 aggregate increase 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 last year. We believe our volumes for the year ended August 31, 2005 were negatively impacted by the conservation efforts of our customers in reaction to record high energy prices. We have increased our marketing efforts to attain new customers, which partially offsets the negative factors described above.

Wholesale Propane. For the year ended August 31, 2005 we sold 70.0 million wholesale propane gallons as compared to 35.7 million 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. Of the 5.6 million gallon aggregate increase in domestic wholesale propane gallons, 0.8 million is primarily due to customers added from an acquisition in December 2003 and a 5.4 million gallon increase in our foreign operations offset by a decrease of 0.6 million gallons related to warmer weather.

Consolidated Results

	Year Ended	
	August 31, 2005	August 31, 2004
Consolidated Information:		
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)
Other, 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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Equity in Earnings (Losses) of Affiliates. Equity in earnings (losses) of affiliates was $(0.4) million for the year ended August 31, 2005, compared to $0.4 million for the year ended August 31, 2004. In connection with the HPL acquisition, we acquired a 50% interest in an unconsolidated affiliate. Our share of losses from this affiliate was $(0.7) million for the year ended August 31, 2005.

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 the interest of our propane segments prior to the Energy Transfer Transactions which is not included in expense for the year ended August 31, 2004, $43.5 million is the result of the borrowings on the Senior Notes and the Revolving Credit Facility in January 2005, $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 million of Senior Notes. We also wrote off $1.5 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. As a partnership, we are not subject to income taxes. However, Oasis Pipe Line Company, Heritage Service Company, and HHI, wholly-owned subsidiaries are corporations that are subject to income taxes. The increase in income tax expense is due to 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 increased income from acquisitions, partially offset by lower taxes on the Oasis Pipeline due to lower taxable income for that entity.

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 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 recorded by HHI.

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.

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EBITDA, as adjusted. EBITDA, as adjusted, increased $216.5 million to $413.2 million for the year ended August 31, 2005 as compared to EBITDA, as adjusted, of $196.7 million for the year ended August 31, 2004. This increase is due to the operating results of our segments described below.

EBITDA, as adjusted, is computed as follows:

	Year Ended	
	August 31, 2005	August 31, 2004
Net income reconciliation		
Net income	$ 349,350	$ 99,152
Gain on sale of discontinued operations, net of income tax expense	(142,469)	
Depreciation and amortization	92,943	48,599
Interest expense	93,017	41,190
Income tax expense on continuing operations	7,295	4,481
Non-cash compensation expense	1,608	42
Other (income) expense, net	(631)	(509)
Depreciation, amortization, and interest of investee	697	440
Depreciation, amortization, and interest of discontinued operations	1,547	2,249
Loss on extinguishment of debt	9,550	
Loss on disposal of assets	330	1,006
EBITDA, as adjusted (a)	$ 413,237	$ 196,650
Heritage EBITDA, as adjusted (b)		$ 52,845
Aggregate EBITDA, as adjusted (b)		$ 249,495

(a) EBITDA, as adjusted, is defined as the Partnership s earnings before interest, taxes, depreciation, amortization and other non-cash items, such as compensation charges for unit issuances to employees, gain or loss on disposal of assets, gain or loss on discontinued operations, and other expenses. We present EBITDA, as adjusted, on a Partnership basis, which includes both the general and limited partner interests. Non-cash compensation expense represents charges for the value of the Common Units awarded under the Partnership s compensation plans that have not yet vested under the terms of those plans and are charges which do not, or will not, require cash settlement. Non-cash income or loss such as the gain or loss arising from our disposal of assets is not included when determining EBITDA, as adjusted. EBITDA, as adjusted, (i) is not a measure of performance calculated in accordance with generally accepted accounting principles and (ii) should not be considered in isolation or as a substitute for net income, income from operations or cash flow as reflected in our consolidated financial statements.

EBITDA, as adjusted, is presented because such information is relevant and is used by management, industry analysts, investors, lenders and rating agencies to assess the financial performance and operating results of our fundamental business activities. Management believes that the presentation of EBITDA, as adjusted, is useful to lenders and investors because of its use in the natural gas and propane industries and for master limited partnerships as an indicator of the strength and performance of the Partnership s ongoing business operations, including the ability to fund capital expenditures, service debt and pay distributions. Additionally, management believes that EBITDA, as adjusted, provides additional and useful information to our investors for trending, analyzing and benchmarking the operating results of our partnership from period to period as

compared to other companies that may have different financing and capital structures. The presentation of EBITDA, as adjusted, allows investors to view our performance in a manner similar to the methods used by management and provides additional insight to our operating results.

EBITDA, as adjusted, is used by management to determine our operating performance, and along with other data as internal measures for setting annual operating budgets, assessing financial performance of our numerous business locations, as a measure for evaluating targeted businesses for acquisition and as a measurement component of incentive compensation. We have a large number of business locations located

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in different regions of the United States. EBITDA, as adjusted, can be a meaningful measure of financial performance because it excludes factors which are outside the control of the employees responsible for operating and managing the business locations, and provides information management can use to evaluate the performance of the business locations, or the region where they are located, and the employees responsible for operating them. To present EBITDA, as adjusted, on a full Partnership basis, we add back the minority interest of the general partner because net income is reported net of the general partner s minority interest. Our EBITDA, as adjusted, includes non-cash compensation expense which is a non-cash expense item resulting from our unit based compensation plans that does not require cash settlement and is not considered during management s assessment of the operating results of the our business. By adding these non-cash compensation expenses in EBITDA, as adjusted, allows management to compare our operating results to those of other companies in the same industry who may have compensation plans with levels and values of annual grants that are different than ours. Other expenses include other finance charges and other asset non-cash impairment charges that are reflected in our operating results but are not classified in interest, depreciation and amortization. We do not include gain or loss on the sale of assets when determining EBITDA, as adjusted, since including non-cash income or loss resulting from the sale of assets increases/decreases the performance measure in a manner that is not related to the true operating results of our business. In addition, our debt agreements contain financial covenants based on EBITDA, as adjusted. For a description of these covenants, please read Financing and Sources of Liquidity in this Form 10-K.

There are material limitations to using a measure such as EBITDA, as adjusted, including the difficulty associated with using it as the sole measure to compare the results of one company to another, and the inability to analyze certain significant items that directly affect a company s net income or loss. In addition, our calculation of EBITDA, as adjusted, may not be consistent with similarly titled measures of other companies and should be viewed in conjunction with measurements that are computed in accordance with GAAP. EBITDA, as adjusted, for the periods described herein is calculated in the same manner as presented by us and Heritage in the past. Management compensates for these limitations by considering EBITDA, as adjusted in conjunction with its analysis of other GAAP financial measures, such as gross profit, net income (loss), and cash flow from operating activities.

(b) The business combination of Energy Transfer Company and Heritage Propane Partners, L.P. and subsidiaries (Heritage), (the Energy Transfer Transaction), on January 20, 2004 resulted in a change of control for accounting purposes, causing Energy Transfer s financial statements to become those of the registrant. Because of the accounting treatment applied in the Energy Transfer Transaction, the reported first quarter fiscal 2004 actual results reflect the operations of Energy Transfer s midstream and transportation and storage businesses for the entire reporting period but not Heritage s propane business for that period. The aggregate results disclosed reflect Heritage s historical results for the period ended January 19, 2004 combined with the historical results of Energy Transfer Company for the nine months 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.

The following reconciliation of Aggregate EBITDA, as adjusted, to net income is presented for comparability purposes only, and is comprised of the aggregate of Energy Transfer Company and Heritage s historical results for the periods presented.

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	For the Period Ended January 19, 2004	Year Ended August 31, 2004
	(Heritage)	(Aggregate)
Net income reconciliation		
Net income	$ 22,644	$ 121,796
Depreciation and amortization	15,389	63,988
Interest expense	12,754	53,944
Income tax expense	20	4,501
Non-cash compensation expense	1,232	1,274
Other, net	66	(443)
Depreciation, amortization, and interest of investee	322	762
Depreciation, amortization, and interest of discontinued operations		2,249
Minority interests in Operating Partnership	178	178
(Gain) loss on disposal of assets	240	1,246
Heritage EBITDA, as adjusted (b)	$ 52,845	
Aggregate EBITDA, as adjusted (b)		$ 249,495

OPERATING RESULTS BY SEGMENT

Midstream Segment

	Year Ended	
	August 31, 2005	August 31, 2004
	(Actual)	(Actual)
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

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 as noted above, 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. We expect the effects of Hurricanes Katrina and Rita to have a positive impact on our earnings in our first quarter of fiscal 2006.

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.

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Selling, General and Administrative Expenses. Midstream 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 cost, 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 or 31%. The increase was principally due to the Texas Chalk and Madison Systems acquisition in November 2004.

Transportation and Storage Segment

	Year Ended	
	August 31, 2005	**August 31, 2004**
	(Actual)	**(Actual)**
Transportation and Storage Segment:		
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 (TXU Shipper) to transport a minimum of 115.6 MMBtu 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. TXU Shipper has notified us that it has elected to reduce the minimum transport volume to 100.0 MMBtu per year beginning in January 2006. The ability to reduce the minimum transport volume was limited to a one-time election. The increase in margin was also due to the Fort Worth Basin expansion completed in May 2005. We expect margins from our ET Fuel System to increase in fiscal 2006 as a result of this expansion and the recently announced expansion projects discussed herein.

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. We expect our margins to increase in the first quarter of fiscal 2006 as a result of the effects of Hurricanes Katrina and Rita in the region where we own these assets.

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 its pipeline and increases in other operating expenses such as compressor and pipeline maintenance and ad valorem taxes.

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Selling, General and Administrative Expenses. Transportation and storage 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 offset by a $1.0 million decrease in legal fees related to a lawsuit that was settled in January 2004 and a $0.3 million decrease in other expenses.

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

	Year Ended		
	August 31, 2005	August 31, 2004	August 31, 2004
	(Actual)	(Actual)	(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 related volumes and customer conservation efforts 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 to our selling prices.

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.

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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 the remaining increase of $2.9 million is primarily due to a general increase in other operating expenses also 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 $11.1 million as compared 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 $6.1 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

	Year Ended		
	August 31, 2005	**August 31, 2004**	**August 31, 2004**
	(Actual)	**(Actual)**	**(Aggregate)**
Wholesale Propane Segment:			
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, and a $15.5 million is related to higher selling prices, $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 $24.8 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, $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.

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. As a comparison, we had aggregate wholesale propane operating expenses of $2.9 million for the year ended August 31, 2004, or an increase of $0.2 million.

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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.

Depreciation and Amortization. For the year ended August 31, 2005, depreciation and amortization in our wholesale propane segments was $0.7 million as compared to aggregate depreciation of $0.6 million for the year ended August 31, 2004. The aggregate increase of $0.1 million is due primarily to the increase in depreciation of assets added through acquisitions.

Operating Loss. For the year ended August 31, 2005, we had 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.

Other

	Year Ended		
	August 31, 2005	**August 31, 2004**	**August 31, 2004**
	(Actual)	**(Actual)**	**(Aggregate)**
Other			
Revenue	$ 6,867	$ 3,464	$ 5,283
Cost of sales	1,742	861	1,304
Operating expenses	4,137	2,233	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.

Fiscal Year Ended August 31, 2004 Compared to the Eleven Months Ended August 31, 2003

The Energy Transfer Transactions affect the comparability of our financial statements for the fiscal year ended August 31, 2004 to the eleven months ended August 31, 2003 because our consolidated financial statements for the fiscal year ended August 31, 2004 include the twelve month results for ETC OLP and its subsidiaries and the results of HOLP, its subsidiaries, and Heritage Holdings only for the period from January 20, 2004 through August 31, 2004. The financial statements of ETC OLP for the eleven months ended August 31, 2003 reflect only the results of ETC OLP and its subsidiaries, and the financial statements of Heritage reflect the results of HOLP and its subsidiaries. The changes in the line items discussed below are a result of these transactions. The aggregate results disclosed below reflect Heritage s historical results from September 1, 2003 until the closing of the Energy Transfer Transactions on January 19, 2004, Heritage s historical results for the fiscal year ended August 31, 2003, and the actual results for the year ended August 31, 2004, for comparability purposes only. This 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.

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Volume. Total volumes of natural gas sales, NGL sales including propane, and natural gas transported by our midstream, transportation and storage, retail propane, domestic wholesale propane, and foreign wholesale propane segments for the fiscal year ended August 31, 2004 and eleven months ended August 31, 2003 are as follows:

	Year Ended August 31, 2004	Eleven Months Ended August 31, 2003
	(actual)	(ETC OLP actual)
Midstream		
Natural gas MMBtu/d	1,026,773	505,725
NGLs bbls/d	6,920	9,332
Transportation and storage		
Natural gas MMBtu/d	1,090,710	921,352

Natural gas sales volumes were 1,026,773 MMBtu/d for the year ended August 31, 2004 compared to 505,725 MMBtu/d for the eleven months ended August 31, 2003, an increase of 521,048 MMBtu/d. NGLs sales volumes decreased from 9,332 Bbls/d for the eleven months ended August 31, 2003 to 6,920 Bbls/d for the year ended August 31, 2004. The increased natural gas sales volumes are the result of our expanded marketing efforts, enhanced relationships with producers and expanded credit facilities with commodity counter parties. As previously discussed, our sales volumes of NGLs vary due to our ability to by-pass our processing plants during unfavorable conditions to process and extract NGLs from our processing plants. The decrease in NGLs sales volumes was attributable to the bypassing of our La Grange plant.

Transportation natural gas volumes increased 169,358 MMBtu/d from 921,352 MMBtu/d for the eleven months ended August 31, 2003 to 1,090,710 for the year ended August 31, 2004. The increase in transportation volumes in principally due to the increased volumes experienced on our Oasis Pipeline and an increase in the differential between the Waha and Katy market hub. The average differential increased $0.093 from $0.156 for the eleven months ended August 31, 2003 to $0.249 for the year ended August 31, 2004 thereby influencing shippers to transport natural gas to regions where natural gas prices were more favorable. The increase was also attributable to the ET Fuel acquisition in June 2004 and the completion of the East Texas Pipeline also in June 2004.

	Year Ended August 31, 2004	Year Ended August 31, 2004	Eleven Months Ended August 31 2003	Eleven Months Ended August 31 2003
	(actual)	(aggregate)	(actual)	(aggregate)
Propane gallons (in thousands)				
Retail	226,209	397,862		375,939
Domestic wholesale	7,071	12,452		15,343
Foreign wholesale	28,648	51,947		58,958

Total gallons	261,928	462,261		450,240

A total of $226.2 million retail propane gallons were sold in the twelve months ended August 31, 2004, with no sales of retail propane gallons reflected in the eleven months ended August 31, 2003. The difference in retail gallons sold is due to the Energy Transfer Transactions described above. We also sold approximately 7.1 million and 28.6 million domestic and foreign wholesale propane gallons, respectively, in the fiscal year ended August 31, 2004, with no sales of domestic or foreign wholesale propane gallons reflected for the eleven months ended August 31, 2003. As a comparison, Heritage would have reflected aggregate volumes of 397.9 million retail propane gallons for the fiscal year ended August 31, 2004 and historical volumes of 376.0 million gallons for the fiscal year ended August 31, 2003. Of the 21.9 million gallon aggregate increase, 27.8 million gallons are the result of volumes sold by customer service locations added through acquisitions, offset by a decrease of 5.9 million gallons that were weather related. We experienced temperatures that were on average, 2.73% warmer in the twelve months ended August 31, 2004 compared to last year and 6.47% warmer than normal during fiscal 2004. Also, as a

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comparison, Heritage would have reflected aggregated volumes of 12.5 million and 52.0 million domestic wholesale and foreign wholesale propane gallons, respectively, for the fiscal year ended August 31, 2004 as compared to historical volumes of 15.3 million and 59.0 million domestic and foreign wholesale propane gallons for the fiscal year ended August 31, 2003. The 2.8 million gallon decrease in domestic wholesale propane gallons is primarily the effect of the loss of two commercial customers to alternative fuel sources, and the 7.0 million gallon decrease in foreign wholesale volumes is due to an exchange contract that was in effect during the fiscal year ended August 31, 2003, which was not economical to renew during fiscal 2004.

Consolidated Results

	Year Ended August 31, 2004	Eleven Months Ended August 31, 2003
	(Actual)	(ETC OLP)
Consolidated Information:		
Revenues	$ 2,346,957	$ 931,027
Cost of sales	1,981,424	825,438
Gross profit	365,533	105,589
Operating expenses	147,374	25,046
Selling, general and administrative	30,471	13,078
Depreciation and amortization	48,599	11,870
Consolidated operating income	$ 139,089	$ 55,595
Equity in earnings of affiliates	363	1,423
Interest expense	(41,190)	(12,456)
Gain (loss) on disposal of assets	(1,006)	
Other income (expense)	509	501
Minority interests	(295)	
Income tax expense	(4,481)	(4,432)
Income from continuing operations	92,989	40,631
Income from discontinued operations, net of income tax expense	6,163	5,994
Net income	$ 99,152	$ 46,625

Equity Income in Affiliates. Equity income in affiliates was $1.4 million for the eleven months ended August 31, 2003 compared to $0.4 million for the fiscal year ended August 31, 2004. The decrease was principally due to the consolidation of the Oasis Pipeline in December 2002.

Interest Expense. Interest expense was $41.2 million for the fiscal year ended August 31, 2004 as compared to $12.5 million for the eleven months ended August 31, 2003. This interest expense reflects the full fiscal year of ETC OLP s interest expense consolidated with the interest expense of HOLP after the Energy Transfer Transactions (from January 20, 2004 through August 31, 2004). Of this increase, $20.7 million is related to the interest expense of HOLP after the Energy Transfer Transactions and $5.9 million is the result of additional interest in our

midstream and transportation and storage segments due to the Energy Transfer Transactions and the acquisition of ET Fuel System in June 2004. In addition, we incurred $8.2 million in deferred financing costs during the year ended August 31, 2004, which we are amortizing on a straight-line basis over the remaining term of the related credit facility and accounting for it in interest expense.

Income Tax Expense. Income tax expense was $4.5 million for the fiscal year ended August 31, 2004 compared to $4.4 million for the eleven months ended August 31, 2003. As a partnership, we are not subject to income taxes. However, Oasis Pipeline, Heritage Service Company, and Heritage Holdings, wholly-owned subsidiaries are corporations that are subject to income taxes. The decrease in income taxes is due to lower taxable income in Oasis Pipeline offset by the increase from the income taxes in Heritage Holdings after the Energy Transfer Transactions.

Income from continuing operations. Income from continuing operations was $93.0 million for the year ended August 31, 2004 compared to $40.6 million for the eleven months ended August 31, 2003. The increase from fiscal 2003 compared to fiscal year 2004 is principally due to the affects of the Energy Transfer Transactions described above together with the increase in acquisition related income.

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Discontinued operations. Income from discontinued operations was $6.2 million for the year ended August 31, 2004 compared to $6.0 million for the eleven months ended August 31, 2003.

Net Income. Net income for the year ended August 31, 2004 was $99.2 million compared to $46.6 million for the eleven months ended August 31, 2003. The affects of the Energy Transactions described above together with the increase in acquisition related income, attributed to this increase.

EBITDA, as adjusted. EBITDA, as adjusted, increased $119.2 million to $196.7 million for the fiscal year ended August 31, 2004 as compared to EBITDA, as adjusted, of $77.5 million for the eleven months ended August 31, 2003. This increase is due to the Energy Transfer Transactions and operating performance described above. This EBITDA, as adjusted, reflects the full twelve months of ETC OLP s EBITDA, as adjusted, consolidated with the EBITDA, as adjusted, of HOLP after the Energy Transfer Transactions (from January 20, 2004 through August 31, 2004). Aggregate total EBITDA, as adjusted, for the periods presented, would have been $249.5 million for the fiscal year ended August 31, 2004 as compared to the aggregate EBITDA, as adjusted, of $188.4 million for the eleven months ended August 31, 2003, which includes the effect of $3.3 million of transaction costs, net of non-cash compensation, which were expensed due to the Energy Transfer Transactions. EBITDA, as adjusted, is computed as follows:

	Fiscal Year Ended	
	August 31, 2004	August 31, 2003
Net income reconciliation		
Net income	$ 99,152	$ 46,625
Depreciation and amortization	48,599	11,870
Interest	41,190	12,456
Taxes	4,481	4,432
Non-cash compensation expense	42	
Other, net	(509)	(501)
Depreciation, amortization, and interest of investee	440	1,003
Depreciation, amortization, and Interest of discontinued operations	2,249	1,591
Minority interests in Operating Partnership		
(Gain) loss on disposal of assets	1,006	
EBITDA, as adjusted (a)	$ 196,650	$ 77,476
Heritage EBITDA, as adjusted (b)	$ 52,845	$ 110,963
Aggregate EBITDA, as adjusted (c)	$ 249,495	$ 188,439

(a) EBITDA, as adjusted, is defined as the Partnership s earnings before interest, taxes, depreciation, amortization and other non-cash items, such as compensation charges for unit issuances to employees, gain or loss on disposal of assets, and other expenses. We present EBITDA, as adjusted, on a Partnership basis, which includes both the general and limited partner interests. Non-cash compensation expense represents charges for the value of the Common Units awarded under the Partnership s compensation plans that have not yet vested under the terms of those plans and are charges which do not, or will not, require cash settlement. Non-cash income or loss such as the gain or loss arising from our disposal of assets is not included when determining EBITDA, as adjusted. EBITDA, as adjusted, (i) is not a measure of

performance calculated in accordance with generally accepted accounting principles and (ii) should not be considered in isolation or as a substitute for net income, income from operations or cash flow as reflected in our consolidated financial statements.

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EBITDA, as adjusted, is presented because such information is relevant and is used by management, industry analysts, investors, lenders and rating agencies to assess the financial performance and operating results of our fundamental business activities. Management believes that the presentation of EBITDA, as adjusted, is useful to lenders and investors because of its use in the natural gas and propane industries and for master limited partnerships as an indicator of the strength and performance of the Partnership s ongoing business operations, including the ability to fund capital expenditures, service debt and pay distributions. Additionally, management believes that EBITDA, as adjusted, provides additional and useful information to our investors for trending, analyzing and benchmarking the operating results of our partnership from period to period as compared to other companies that may have different financing and capital structures. The presentation of EBITDA, as adjusted, allows investors to view our performance in a manner similar to the methods used by management and provides additional insight to our operating results.

EBITDA, as adjusted, is used by management to determine our operating performance, and along with other data as internal measures for setting annual operating budgets, assessing financial performance of our numerous business locations, as a measure for evaluating targeted businesses for acquisition and as a measurement component of incentive compensation. We have a large number of business locations located in different regions of the United States. EBITDA, as adjusted, can be a meaningful measure of financial performance because it excludes factors which are outside the control of the employees responsible for operating and managing the business locations, and provides information management can use to evaluate the performance of the business locations, or the region where they are located, and the employees responsible for operating them. To present EBITDA, as adjusted, on a full Partnership basis, we add back the minority interest of the general partner because net income is reported net of the general partner s minority interest. Our EBITDA, as adjusted, includes non-cash compensation expense which is a non-cash expense item resulting from our unit based compensation plans that does not require cash settlement and is not considered during management s assessment of the operating results of the our business. By adding these non-cash compensation expenses in EBITDA, as adjusted, allows management to compare our operating results to those of other companies in the same industry who may have compensation plans with levels and values of annual grants that are different than ours. Other expenses include other finance charges and other asset non-cash impairment charges that are reflected in our operating results but are not classified in interest, depreciation and amortization. We do not include gain or loss on the sale of assets when determining EBITDA, as adjusted, since including non-cash income or loss resulting from the sale of assets increases/decreases the performance measure in a manner that is not related to the true operating results of our business. In addition, our debt agreements contain financial covenants based on EBITDA, as adjusted. For a description of these covenants, please read - Financing and Sources of Liquidity in this Form 10-K.

There are material limitations to using a measure such as EBITDA, as adjusted, including the difficulty associated with using it as the sole measure to compare the results of one company to another, and the inability to analyze certain significant items that directly affect a company s net income or loss. In addition, our calculation of EBITDA, as adjusted, may not be consistent with similarly titled measures of other companies and should be viewed in conjunction with measurements that are computed in accordance with GAAP. EBITDA, as adjusted, for the periods described herein is calculated in the same manner as presented by us and Heritage in the past. Management compensates for these limitations by considering EBITDA, as adjusted in conjunction with its analysis of other GAAP financial measures, such as gross profit, net income (loss), and cash flow from operating activities.

The following reconciliation of Aggregate EBITDA, as adjusted, to net income is presented for comparability purposes only, and is comprised of the aggregate of Energy Transfer Company and Heritage s historical results for the periods presented.

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	For the Period Ended January 19, 2004 (Heritage)	Year Ended August 31, 2004 (Aggregate)	Year Ended August 31, 2003 (Heritage Historical)	Year Ended August 31, 2003 (Aggregate)
Net income reconciliation				
Net income	$ 22,644	$ 121,796	31,142	77,767
Depreciation and amortization	15,389	63,988	37,959	49,829
Interest expense	12,754	53,944	35,740	48,196
Income tax expense	20	4,501	1,023	5,455
Non-cash compensation expense	1,232	1,274	1,159	1,159
Other, net	66	(443)	3,213	2,712
Depreciation, amortization, and interest of investee	322	762	901	1,904
Depreciation, amortization, and interest of discontinued operations		2,249		1,591
Minority interests in Operating Partnership	178	178	256	256
(Gain) loss on disposal of assets	240	1,246	(430)	(430)
Heritage EBITDA, as adjusted (b)	$ 52,845		110,963	
Aggregate EBITDA, as adjusted (b)		$ 249,495		188,439

OPERATING RESULTS BY SEGMENT

Midstream Segment

	Year Ended August 31, 2004 (Actual)	Eleven Months Ended August 31, 2003 (ETC OLP)
Midstream Segment:		
Revenues	$ 1,880,663	$ 899,086
Cost of sales	1,787,849	832,874
Gross Margin	92,814	66,212
Operating expenses	12,541	11,193
General and administrative	10,387	8,057
Depreciation and amortization	9,637	9,056

Segment operating income	$ 60,249	$ 37,906

Gross Margin. Midstream gross margin increased $26.6 million from $66.2 million for the eleven months ended August 31, 2003 to $92.8 million for the year ended August 31, 2004. the increase is principally attributable to expanding our producer services activities and increases in sales volumes during the year ended August 31, 2004. We also had the benefit of one additional month for the 2004 period compared to the 2003 period.

Operating Expenses. Midstream operating expenses increased from $11.2 million for the eleven months ended August 31, 2003 to $12.5 million for the year ended August 31, 2004. The increase was principally attributable to a $1.2 million effect of reporting on an additional month and $0.1 increase in miscellaneous expenses during the year ended August 31, 2004 compared to the eleven months ended August 31, 2003.

Selling, General and Administrative Expenses. Midstream general and administrative expenses increased $2.3 million from $8.1 million for the eleven months ended August 31, 2003 to $10.4 million principally due to a $1.2 million effect of reporting on an additional month for the year ended August 31, 2004, a $2.7 million increase in compensation expense and a $0.4 million increase in merger and reporting compliance expenses. The increase was offset by a $2.0 million increase in costs allocated to the transportation and storage segment for certain management services provided by the midstream.

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Depreciation and Amortization. Midstream depreciation and amortization increased $0.5 million from $9.1 million for the eleven months ended August 31, 2003 to $9.6 million for the year ended August 31, 2004 due to an additional month in the 2004 reporting period.

Transportation and Storage Segment

	Year Ended August 31, 2004	Eleven Months Ended August 31, 2003
	(Actual)	(ETC OLP)
Transportation and Storage Segment:		
Revenues	$ 113,938	$ 41,500
Cost of sales	11,270	2,123
Gross Margin	102,668	39,377
Operating expenses	30,571	13,853
General and administrative	8,372	5,021
Depreciation and amortization	7,426	2,814
Segment operating income	$ 56,299	$ 17,689

Gross Margin. Transportation and storage gross margin was $102.7 million for the year ended August 31, 2004 compared to $39.4 million for the eleven months ended August 31, 2003. The significant increase in transportation and storage revenues is principally due to the following:

Accounting for Oasis Pipeline. As discussed above, we accounted for the Oasis Pipeline as an equity method investment prior to December 27, 2002 when we purchased the remaining 50% in Oasis Pipeline. As a result, the eleven months ended August 31, 2003 only includes the results of operations subsequent to December 27, 2002.

Increased volumes. During the year ended August 31, 2004, we transported 1,090,710 MMBtu/d through our transportation pipelines compared to 921,352 MMBtu/d during the period from December 27, 2002 to August 31, 2003, an increase of 169,358 MMBtu/d or 18.4%. The volume increase is a result of our decision to pursue additional volumes on the middle and west end of the system on the Oasis Pipeline, the acquisition of the ET Fuel System in June 2004, and the completion of the East Texas Pipeline in June 2004. We believe that we will be able to increase throughput on, and therefore gross margin from, the ET Fuel System in future years through the addition of interconnects with other pipelines and other industrial end-users, the addition of new customers and more active management of the ET Fuel System and storage facilities to capitalize market opportunities. In addition, a wide basis differential between the Waha and Katy market hubs provides an incentive to transport increased volumes of natural gas to a more attractive marketplace.

Operating Expenses. Transportation and storage operating expenses were $30.6 million for the year ended August 31, 2004 compared to $13.9 million for the eleven months ended August 31, 2003, an increase of $16.7 million or 120.1%. The increase was principally attributable to the Oasis Pipeline being accounted for as an equity method investment prior to December 27, 2002, $11.0 million in additional operating expenses

related to the acquisition of the ET Fuel System in June 2004, and the completion of the East Texas Pipeline in June 2004.

Selling, General and Administrative Expenses. Transportation and storage general and administrative expenses increased $3.4 million during the eleven months ended August 31, 2003 from $5.0 million to $8.4 million for the year ended August 31, 2004. The increase is principally attributable to the 2003 reporting period not including general and administrative expenses for the Oasis Pipeline prior to December 27, 2002 as it was accounted for as an equity method investment.

Depreciation and Amortization. Transportation and storage depreciation and amortization increased $4.6 million from $2.8 million for the eleven months ended August 31, 2003 to $7.4 million for the year ended August 31, 2004. The increase was attributable to increased depreciation as a result of the consolidation of the Oasis Pipeline in December 2002 and the acquisition of the ET Fuel System in June 2004.

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Retail Propane Segment

	Year Ended August 31, 2004 (Actual)	Year Ended August 31, 2004 (Aggregate) (unaudited)	Year Ended August 31, 2003 (Aggregate) (unaudited)
Retail Propane Segment:			
Retail propane revenues	$ 315,177	$ 536,636	$ 463,392
Other propane related revenues	34,167	60,646	55,557
Retail propane cost of sales	174,769	296,206	236,307
Other propane related cost of sales	9,602	17,512	16,073
Operating expenses	100,093	158,471	144,929
Selling General and administrative	6,746	11,080	12,825
Depreciation and amortization	30,925	45,979	37,113
Segment operating income	$ 27,209	$ 68,034	$ 71,702

Revenues. For the year ended August 31, 2004, we had retail propane revenues of $315.2 million with no retail propane sales reflected in the fiscal year ended August 31, 2003. These revenues reflect only the amounts earned after the Energy Transfer Transactions (from January 20, 2004 through August 31, 2004). As a comparison, for the fiscal ended August 31, 2004, Heritage would have reflected aggregate retail propane revenues of $536.6 million as compared to aggregate revenues of $463.4 million in the fiscal year ended August 31, 2003 for Heritage. Of the $73.2 million increase from Heritage, $37.4 million is due to the increase in volumes sold by customer service locations added through acquisitions, $43.7 million is due to higher selling prices, offset by a decrease of $7.9 million due to the decrease in weather related volumes described above. We had other propane related revenues of $34.2 million for the year ended August 31, 2004 with no other propane related revenues for fiscal year 2003. As a comparison for the fiscal year ended August 31, 2004, we would have reflected aggregate other propane related revenues of $60.6 million compared to aggregate other propane related revenues of $55.6 million for the year ended August 31, 2003. The aggregate increase of $5.0 million is primarily increases from acquisitions.

Costs of Sales. For the fiscal year ended August 31, 2004, we had retail propane cost of sales of $174.8 million, with no retail propane cost of sales reflected in the fiscal year ended August 31, 2003 These costs reflect only the amounts that were incurred after the Energy Transfer Transactions (from January 20, 2004 through August 31, 2004). As a comparison, for the fiscal year ended August 31, 2004, aggregated retail propane cost of sales would have been $296.2 million as compared to the historical cost of sales of $236.3 million in the fiscal year ended August 31, 2003. Of the $59.9 million aggregate increase from Heritage, $16.3 million reflects changes in volumes described above and $43.6 reflects the increase due to higher selling prices. We had other propane related cost of sales of $9.6 million for the year ended August 31, 2004 with no other propane related cost of sales reflected for the fiscal year ended August 31, 2003. As a comparison, we would have reflected aggregated other propane related cost of sales of $17.5 million for the year ended August 31, 2004 with aggregate other propane related cost of sales of $16.1 million for the year ended August 31, 2003. The increase of $6.4 million is primarily related to increases from acquisitions.

Operating Expenses. Total operating expenses for the retail propane operations were $100.1 million for the fiscal year ended August 31, 2004, which reflects from the date of the Energy Transfer Transaction. Our retail propane operations would have reflected total aggregate operating expense of $158.5 million for the full year as compared to Heritage s historical total operating expenses of $144.9 million for the year ended August 31, 2003, or an increase of $13.6 million. Of this aggregate increase approximately $12.4 million related to employee related expenses due to an increase in our employee base from acquisitions. During fiscal 2004, Heritage purchased the other 50% of Bi-State Partnership, which

accounted for as an equity method investment prior to the purchase in December 2003.

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Selling, General and Administrative Expenses. For the year ended August 31, 2004, selling, general and administrative expenses for our retail propane segment were $6.7 million with no retail propane selling general and administrative expenses for the year ended August 31, 2003. As a comparison, aggregate retail propane selling, general and administrative expenses would have been $11.1 million for the year ended August 31, 2004 compared to aggregate retail propane selling, general and administrative expenses of $12.8 million for the fiscal year ended August 31, 2003.

Depreciation and Amortization. For the year ended August 31, 2004, depreciation and amortization in our retail propane segment was $30.9 with no depreciation expense reflected for the year ended August 31, 2003. As a comparison, we would have had aggregate depreciation and amortization of $46.0 million for the year ended August 31, 2004 compared to aggregate depreciation and amortization of $37.1 million for the year ended August 31, 2003. The aggregate increase of $8.9 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, 2004, we had retail propane operating income of $27.2 with no retail propane operating income reflected for the year ended August 31, 2003. As a comparison, we would have had aggregate operating income for the year ended August 31, 2004 of $68.0 million compared to aggregate operating income of $71.7 million for the year ended August 31, 2003. This aggregate decrease is due to changes in revenues and expenses described above.

Wholesale Propane Segment

	Year Ended August 31, 2004 (Actual)	Year Ended August 31, 2004 (Aggregate) (unaudited)	Year Ended August 31, 2003 (Aggregate) (unaudited)
Wholesale Propane Segment:			
Revenues	$ 27,345	$ 47,941	$ 47,366
Cost of sales	24,871	43,410	43,636
Operating expenses	1,936	2,912	3,508
Selling, general and administrative	918	1,443	1,213
Depreciation and amortization	432	626	517
Segment operating loss	$ (812)	$ (450)	$ (1,508)

Revenues. For the fiscal year ended August 31, 2004, we had wholesale propane revenues of $27.3 million, with no wholesale propane revenues reflected in the eleven months ended August 31, 2003. These revenues reflect only the amounts that were incurred after the Energy Transfer Transactions (from January 20, 2004 through August 31, 2004). Aggregate wholesale propane revenues would have been $47.9 million for the fiscal year ended August 31, 2004 as compared to aggregate revenues of $47.4 million for the fiscal year ended August 31, 2003.

Costs of Sales. For the fiscal year ended August 31, 2004, we had wholesale propane cost of sales of $24.8 million, with no wholesale propane cost of sales reflected in the fiscal year ended August 31, 2003. These costs reflect only the amounts that were incurred after the Energy Transfer

Transactions (from January 20, 2004 through August 31, 2004). Aggregate wholesale propane cost of sales would have been $43.4 million as compared to historical cost of sales of $43.6 million for the fiscal year ended August 31, 2003.

Operating Expenses. For the year ended August 31, 2004, operating expenses for our wholesale propane segment were $1.9 million with no wholesale propane operating expenses reflected for the year ended August 31, 2003. As a comparison, we had aggregate wholesale propane operating expenses of $2.9 million for the year ended August 31, 2004, compared to aggregated wholesale propane operating expenses of $3.5 million for the fiscal year ended August 31, 2003.

Selling, General and Administrative Expenses. Selling, general and administrative expenses for our wholesale propane segment were $0.9 for the year ended August 31, 2004 with no wholesale propane selling, general

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and administrative expenses reflected in the year ended August 31, 2003. As a comparison, we had aggregate wholesale selling, general, and administrative expenses of $1.4 million for the year ended August 31, 2004 compared to aggregate wholesale selling, general and administrative expenses of $1.2 million for the year ended August 31, 2003.

Depreciation and Amortization. For the year ended August 31, 2004, depreciation and amortization in our wholesale propane segments was $0.4 million with no wholesale depreciation and amortization reflected in the year ended August 31, 2003. As a comparison, we had aggregate depreciation of $0.6 million for the year ended August 31, 2004 compared to aggregate wholesale deprecation of $0.5 million for the year ended August 31, 2003.

Operating Loss. For the year ended August 31, 2004, we had domestic wholesale propane operating loss of $0.8 million compared to aggregate total operating loss of $1.5 million for the year ended August 31, 2003.

Other

	Year Ended		
	August 31, 2004	**August 31, 2004**	**August 31, 2003**
	(Actual)	**(Aggregate)**	**(Aggregate)**
Other			
Revenue	$ 3,465	$ 5,283	$ 5,161
Cost of sales	861	1,304	1,139
Operating expenses	2,234	3,614	3,694
Depreciation and amortization	179	321	329
Other operating income (loss)	$ 191	$ 44	$ (1)
Unallocated selling, general and administrative expenses	$ 4,047	$ 9,288	$

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

For the year ended August 31, 2004, the total unallocated selling, general, and administrative expenses were $4.0 million with no unallocated selling, general, and administrative expense reflected for the year ended August 31, 2003. Aggregate total unallocated selling, general, and administrative expense for the year ended August 31, 2004 would have been $9.3 million with no aggregate total unallocated selling, general and administrative expenses for the year ended August 31, 2003.

Liquidity and Capital Resources

Our ability to satisfy our obligations 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 $21.3 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 $16.0 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 $534.0 million in the next fiscal year; and customer propane tanks for which we expect to expend $18.9 million in the next fiscal year; and

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

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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 season 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.

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 new well connects.

In connection with the HPL acquisition, we now 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.

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 HPL System, and other factors.

Operating Activities. Cash provided by operating activities during the year ended August 31, 2005, was $169.4 million as compared to cash provided by operating activities of $162.7 million for the year ended August 31, 2004. The net cash provided by operations for the year ended August 31, 2005 consisted of net income of $349.3 million, non-cash charges of $(28.7) million, principally gain on the sale of discontinued operations and depreciation and amortization, and a decrease in working capital of $151.2 million. 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, purchase of inventories related to the propane and transportation and storage operations, and the Energy Transfer Transactions.

Investing Activities. Cash used in investing activities during the year ended August 31, 2005 of $1,133.7 million is comprised of cash paid for acquisitions of $1,131.8 million, $196.5 million invested for maintenance and growth capital expenditures needed to sustain operations at current levels and to support growth of operations, and cash invested in affiliates of $2.3 million. Cash used in investing activities also includes proceeds from the sale of discontinued operations of $191.6 million and proceeds from the sale of idle property of $5.3 million. The cash paid for acquisitions included $1,039.5 million paid for the acquisition of the HPL System, $63.0 million for the Texas Chalk and Madison Systems

acquisitions and $3.8 million for the purchase of the remaining interests in Vantex that we did not previously own. Cash paid for acquisitions also included $25.5 million expended for retail propane acquisitions. In addition to cash paid for acquisitions, we also issued $2.5 million of Common Units in connection with two propane acquisitions.

Financing Activities. Cash provided by financing activities during the year ended August 31, 2005 was $0.9 million. In January 2005, we successfully completed our issuance of $750.0 million in Rule 144A private placement

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Senior Notes. Net proceeds of approximately $741.0 million were used to repay borrowings of $725.0 million and accrued interest outstanding under our then existing ETC OLP Term Loan Facility and ETC OLP Revolving Credit Facility. We also entered into a $700.0 million Revolving Credit Facility in January 2005. Effective June 2, 2005 we increased the amount available under the Revolving Credit Facility from $700.0 million to $800.0 million. The Revolving Credit Facility had net borrowings $186.0 million outstanding as of August 31, 2005, of which the majority was used to finance the purchase of natural gas inventory to be stored in our Bammel storage facility and margin calls with our brokers. The Swingline loan option of the Revolving Credit Facility provided $15.0 million of net proceeds that were used for general partnership purposes. On July 29, 2005 in a Rule 144A private placement offering, we issued $400.0 million in aggregate principal amount of Senior Notes. The net proceeds of approximately $397.1 million from the sale of the 2012 Unregistered Notes were used to retire a portion of our outstanding indebtedness under our revolving credit facility, to fund our recently announced capital expansion projects and for general partnership purposes.

ETC OLP borrowed $80.0 million under its Revolving Credit Facility of which $60.0 million was used to fund the acquisition of the Texas Chalk and Madison Systems. The remaining $20.0 million was used for general partnership purposes. The $80.0 million was repaid during the second quarter of fiscal year 2005. Net cash provided by financing activities also included $174.6 million of proceeds from a short-term loan with ETE, whereby ETC OLP borrowed the funds to acquire the working natural gas inventory stored in the Bammel storage facilities in connection with the HPL acquisition. The loan was paid in full during the third quarter of fiscal year 2005. ETC OLP incurred $3.1 million in debt issuance costs associated with the loan agreement which were amortized into interest expense or written off at the time of the repayment of the loan.

Cash provided by financing activities includes the net increase in HOLP s Working Capital Facility of $2.1 million, a net increase in HOLP s Acquisition Facility of $19.0 million and a net decrease in HOLP s long-term debt of $31.0 million. The increase in the Acquisition Facility is due to funding of acquisitions of propane businesses and other growth capital. The decrease in HOLP s long-term debt is due to the re-payment of required principal on HOLP s senior secured notes.

On January 26, 2005, we placed $350.0 million of Common Units in a private placement to institutional investors as part of the financing of the acquisition of HPL. In this private placement we issued 6,296,294 (post-split) unregistered Common Units for total consideration of $170.0 million, and we became obligated under a Units Purchase Agreement dated January 14, 2005 to issue an additional 6,666,666 (post-split) Common Units for total consideration of $180.0 million. These Common Units were issued pursuant to an effective shelf registration statement on March 18, 2005. The proceeds from these private placements were used to finance a portion of the HPL acquisition. On June 20, 2005 we issued 1,640,000 Common Units to a group of our executive managers for $52.4 million, On July 26, 2005, we completed the sale of 3,000,000 Common Units in a private sale to an institutional investor. The Common Units were issued pursuant to the Partnership s effective shelf registration statement and the proceeds of $105.6 million were used by the Partnership to retire a portion of the outstanding indebtedness on its revolving credit facility. We paid $0.3 million in equity issue costs associated with the issuance of Common Units. The General Partner contributed $10.4 million to maintain its 2% interest in the Partnership in connection with the Common Units issued in the private placements and $2.5 million units issued in connection with certain acquisitions.

Cash received from financing activities is reduced by the distributions we paid to our Common Unitholders and the General Partner s 2% interest of $207.0 million, and other financing costs of $19.7 million related to the issuance of the $750.0 million Senior Notes, the $400 million Senior Notes, and other debt.

Financing and Sources of Liquidity

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 the Partnership s operations. Heritage (the predecessor to

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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. On October 15, 2004, we paid a quarterly distribution of $0.4125 per unit, or $1.65 per unit annually, to our Unitholders of record at the close of business on October 7, 2004. On January 14, 2005, we paid a quarterly distribution of $0.4375 per unit, or $1.75 per unit annually, to our Unitholders of record at the close of business on January 5, 2005. On April 14, 2005, we paid a quarterly distribution of $0.4625 per unit, or $1.85 per unit annually, an increase of $0.025 per unit per quarter, or $0.10 annually. On July 15, 2005, we paid a quarterly distribution of $0.4875 per Common Unit, or $1.95 per unit annually, an increase of $0.10 per Common Unit on an annualized basis. On September 2, 2005, we declared a distribution for the fourth quarter ended August 31, 2005 of $0.500 per Common Unit, or $2.00 per unit annually, an increase of $0.05 per Common Unit on an annualized basis. The distribution was paid on October 14, 2005 to Unitholders of record at the close of business on September 30, 2005. In addition to these quarterly distributions, our General Partner received quarterly distributions for its general partner interest in us, and incentive distributions to the extent the quarterly distribution exceeded $0.275 per unit.

Description of Indebtedness

The Partnership s indebtedness 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 and a Revolving Credit Facility that allows for borrowings of up to $800.0 million through January 18, 2010. We also currently maintain separate credit facilities for HOLP. Prior to January 18, 2005, we maintained a separate credit facility for ETC OLP, which was paid off using net proceeds received from us pursuant to our offering of 5.95% Senior Notes due 2015. 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 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, 2005, we were in compliance with all financial requirements, tests, limitations, and covenants related to financial ratios under our existing credit agreements.

Senior Notes.

On January 18, 2005, in a Rule 144A private placement offering, we issued $750.0 million in aggregate principal amount of 5.95% Senior Notes due on February 1, 2015 (the 2015 Unregistered Notes). We recorded a discount of $2.2 million and debt issue costs of $7.4 million in connection with the issuance of the 2015 Unregistered Notes. The net proceeds of approximately $741.0 million were used to repay the indebtedness and accrued interest outstanding under the then existing credit facilities that were previously secured by the assets of ETC OLP. On July 29, 2005, we completed the exchange of the 2015 Unregistered Notes for substantially similar notes registered under the Securities Act of 1933, as amended.

On July 29, 2005, in a Rule 144A private placement offering, we issued $400.0 million in aggregate principal amount of 5.65% Senior Notes due on August 1, 2012 (the 2012 Unregistered Notes and together with the 2015 Unregistered Notes, the ETP Senior Notes). We recorded a discount of $0.4 million in connection with the issuance of the 2012 Unregistered Notes. The net proceeds of approximately $397.1 million from the sale of the 2012 Unregistered Notes were used to retire a portion of our outstanding indebtedness under our revolving credit facility, to fund our recently announced capital expansion projects and for general partnership purposes.

The ETP Senior Notes represent senior unsecured obligations of the Partnership and rank equally with all of our other existing and future unsecured and unsubordinated indebtedness. The ETP Senior Notes are jointly and severally guaranteed by ETC OLP and all of the direct and indirect wholly-owned 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 ETP 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 ETP 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 ETP 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.

Revolving Credit Facility.

On January 18, 2005 we entered into a $700.0 million Revolving Credit Facility available through January 18, 2010. Effective June 2, 2005, the Revolving Credit Facility was amended to increase the borrowing capacity from $700.0 million to $800.0 million. The Revolving Credit Facility also offers a Swingline loan option the maximum borrowing of $30.0 million and a daily rate based on the London market. Amounts borrowed under the Credit Facility bear interest at a rate based on either a Eurodollar rate, or a prime rate. The weighted average interest rate was 4.827% as of August 31, 2005. The maximum commitment fee payable on the unused portion of the facility is 0.30%. As of August 31, 2005, $201.0 million was outstanding under the Revolving Credit Facility which includes $15.0 million under the Swingline loan option. There was also $11.3 million in letters of credit outstanding as of August 31, 2005, which reduced the amount available for borrowing under the Revolving Credit Facility. Total amount available under the Credit Agreement as of August 31, 2005 was $587.7 million after deducting $11.3 million in letters of credit.

The ETP Revolving Credit Facility requires that, on the last day of each of our fiscal quarters, the ratio of our Consolidated Funded Debt (as defined in the credit agreement relating to the ETP Revolving Credit Facility) to our Consolidated EBITDA (as defined in the credit agreement relating to the ETP Revolving Credit Facility) for the four fiscal quarters most recently ended must be no greater than 4.5 to 1.0 except that, on the last day of any fiscal quarter in which we or our subsidiaries makes an acquisition with a purchase price of $50.0 million or more, such ratio must be no greater than 5.0 to 1.0. In addition, this facility requires that the ratio of our Consolidated EBITDA (as defined in the credit agreement relating to the ETP Revolving Credit Facility) to our Consolidated Interest Expense (as defined in the credit agreement relating to the ETP Revolving Credit Facility) for the four fiscal quarters most recently ended must not be less than 3.0 to 1.0. We satisfied our leverage ratio covenants for the fiscal years ended August 31, 2005 and 2004 and therefore were able to make the cash distributions at the levels we distributed during these periods.

ETC OLP and its designated subsidiaries act as guarantors of the debt obligations under the ETP Revolving Credit Facility. If we were to default on the ETP Revolving Credit Facility, ETC OLP and its designated subsidiaries would be responsible for full repayment of our debt obligations under the ETP Revolving Credit Facility. The ETP Revolving Credit Facility is unsecured and the lenders thereunder have equal rights to holders of our other current and future unsecured senior debt.

HOLP Facilities

Working Capital Facility. Effective March 31, 2004, HOLP entered into the Third Amended and Restated Credit Agreement, which includes a $75.0 million senior revolving working capital facility available through December 31, 2006 (the HOLP Working Capital Facility). Amounts borrowed under the working capital facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The weighted average interest rate was 5.308% for the amount outstanding at August 31, 2005. HOLP must reduce the principal amount of working capital borrowings to $10.0 million for a period of not less than 30 consecutive days at least one time during each fiscal year. HOLP completed the 30-day clean down requirement under the HOLP Working Capital Facility on June 14, 2005. All receivables, contracts, equipment, inventory, general intangibles, cash concentration accounts of HOLP, and the capital stock of HOLP s subsidiaries secure the HOLP Working Capital Facility. A $5.0 million Letter of Credit issuance is available to HOLP for up to 30 days prior to the maturity date of the Working Capital Facility. As of August 31, 2005, the HOLP Working Capital Facility had a balance outstanding of $26.7 million and $1.0 million of outstanding letters of credit. Letter of Credit Exposure plus the Working Capital Loan cannot exceed the $75,000 maximum Working Capital Facility.

Acquisition Facility. The Third Amended and Restated Credit Agreement also includes a $75.0 million senior revolving acquisition facility that is available through December 31, 2006 (the HOLP Acquisition Facility). Amounts borrowed under the HOLP Acquisition Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The weighted average interest rate was 5.182% for the amount outstanding at August 31, 2005. The maximum commitment fee payable on the unused portion of the facility is 0.50%. All receivables, contracts,

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equipment, inventory, general intangibles, cash concentration accounts of HOLP, and the capital stock of HOLP s subsidiaries secure the HOLP Acquisition Facility. As of August 31, 2005, the HOLP Acquisition Facility had a balance outstanding of $42.0 million.

Effective September 1, 2005, HOLP entered into the Second Amendment to the Third Amended and Restated Credit Agreement. The amendment in its entirety states as follows: In no event shall the Letter of Credit Exposure exceed $15.0 million at any time . All of the remaining terms, provisions and conditions of the existing Credit Agreement continue in full force and effect as within the March 31, 2004 Third Amended and Restated Credit Amendment noted above.

Senior Secured Notes. In connection with our initial public offering, on June 25, 1996, HOLP entered into a Note Purchase Agreement whereby HOLP issued $120 million principal amount of 8.55% Senior Secured Notes (the HOLP Notes) with institutional investors. Interest is payable semi-annually in arrears on each December 31 and June 30. The HOLP Notes have a final maturity of June 30, 2011, with ten equal mandatory repayments of principal, which began on June 30, 2002. At August 31, 2005, $72 million of principal debt was outstanding under the HOLP Notes.

On November 19, 1997, HOLP entered into a Note Purchase Agreement that provided for the issuance of up to $100 million of senior secured promissory notes (HOLP Medium Term Note Program) if certain conditions were met. An initial placement of $32 million (Series A and B), at an average interest rate of 7.23% with an average 10-year maturity, was completed at the closing of the HOLP Medium Term Note Program. Interest is payable semi-annually in arrears on each November 19 and May 19. An additional placement of $15 million (Series C, D and E), at an average interest rate of 6.59% with an average 12-year maturity, was completed in March 1998. Interest is payable on Series C and D semi-annually in arrears on each September 13 and March 13. The proceeds of the placements were used to refinance amounts outstanding under the HOLP Acquisition Facility. No future placements are permitted under the unused portion of the HOLP Medium Term Note Program. During the fiscal year ended August 31, 2003, Heritage used $3.9 million and $5.0 million of the proceeds from the issuance of 1,610,000 of Common Units to retire the balance of the Series D and Series E Senior Secured Notes, respectively. At August 31, 2005, $28.7 million of principal debt was outstanding under the HOLP Medium Term Note Program.

On August 10, 2000, HOLP entered into a Note Purchase Agreement (HOLP Senior Secured Promissory Notes) that provided for the issuance of up to $250 million of fixed rate senior secured promissory notes if certain conditions were met. An initial placement of $180 million (Series A through F) at an average rate of 8.66% with an average 13-year maturity was completed in conjunction with the merger with U.S. Propane. Interest is payable quarterly. The proceeds were used to finance the transaction with U.S. Propane and retire a portion of existing debt. On May 24, 2001, HOLP issued an additional $70 million (Series G through I) of the Senior Secured Promissory Notes to a group of institutional lenders with 7-, 12- and 15-year maturities and an average coupon rate of 7.66%. HOLP used the net proceeds from the Senior Secured Promissory Notes to repay the balance outstanding under the HOLP Acquisition Facility and to reduce other debt. Interest is payable quarterly. During the fiscal year ended August 31, 2003, HOLP used $7.5 million and $19.5 million of the proceeds from the issuance of 1,610,000 of Common Units to retire a portion of the Series G and Series H Senior Secured Promissory Notes, respectively. At August 31, 2005, $196.7 million of principal debt was outstanding under the HOLP Senior Secured Promissory Notes.

Covenants Related to HOLP Credit Agreements. The Note Agreements for each of the HOLP Notes, the HOLP Medium Term Note Program and the HOLP Senior Secured Promissory Notes, and HOLP s bank credit facilities contain customary restrictive covenants applicable to HOLP, changes in ownership of HOLP, including limitations on the level of additional indebtedness, creation of liens, and substantial disposition of assets. These covenants require HOLP to maintain ratios of Consolidated Funded Indebtedness to Consolidated EBITDA (as defined in the Note Purchase Agreements of HOLP) of not more than 4.75 to 1.00 and Consolidated EBITDA to Consolidated Interest Expense (as defined in the Note Purchase Agreements of HOLP) of not less than 2.25 to 1. For purposes of calculating the ratios under the Note Purchase Agreements of HOLP, Consolidated EBITDA is based upon the HOLP s EBITDA, as adjusted, during 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. The Note Purchase Agreements also provide that HOLP may declare, make, or incur a liability to make, a restricted

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payment 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 (As defined in the Note Purchase Agreements of HOLP) with respect to the immediately preceding quarter; (b) no default or event of default exists before such restricted payment; and (c) HOLP s restricted payments are not greater than the product of HOLP s Percentage of Aggregate Partner Obligations (as defined in the Note Purchase Agreements). The Note Purchase 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 HOLP Notes. 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, Available Cash is required to reflect 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 HOLP s bank credit facilities and the Note Agreements could negatively impact our ability to incur additional debt and our ability to pay distributions. We are required to measure these financial tests and covenants quarterly and were in compliance with all financial requirements, tests, limitations, and covenants related to financial ratios under the Senior Secured Notes, Medium Term Note Program, Senior Secured Promissory Notes, and the bank credit facilities at August 31, 2005. All receivables, contracts, equipment, inventory, general intangibles, cash concentration accounts, and the capital stock of HOLP and its subsidiaries secure the 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. Since April 18, 2004 the Notes have rated investment grade or better thereby alleviating the requirement that we pay the additional 1% interest.

ETC OLP Facilities

In January 2005, ETC OLP repaid in full the amounts borrowed under its $725.0 million term loan facility and its $225.0 million revolving credit facility using net proceeds received from our private placement of $750.0 million of 5.95% Senior Notes due 2015.

Loan from affiliate. In January 2005, ETC OLP entered into a short-term loan agreement with ETE, whereby ETC OLP borrowed approximately $174.6 million in connection with the acquisition of the Houston Pipeline System to purchase from the sellers the working gas inventory of natural gas stored in the Bammel storage facility. The six-month note provided for the payment of interest based on the Eurodollar Rate plus 3.0% per annum. The loan was repaid in full during the quarter ended May 31, 2005 and the unamortized debt issuance costs were written off and accounted for as loss on extinguishment of debt in the consolidated statements of operations for the year ended August 31, 2005.

Contractual Obligations

The following table summarizes our long-term debt and other contractual obligations as of August 31, 2005:

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	$ 1,715,054	$ 39,349	$ 137,123	$ 285,075	$ 1,253,507
Interest on fixed rate long-term debt (a)	706,551	92,940	176,374	162,350	274,887

Purchase commitments	52,196	52,196			
Operating lease obligations	15,592	5,881	5,435	3,298	978
Totals	$ 2,489,393	$ 190,366	$ 318,932	$ 450,723	$ 1,529,372

(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 Facility, Revolving Credit Facility Swingline loan option, long term portion of our Senior Revolving Working Capital Facility or our Senior Revolving Acquisition Facility. As of August 31, 2005, variable

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rate interest on our outstanding balance of variable rate debt of $269.6 million would be $13.3 million on an annual basis. See Note 7 Working Capital Facility and Long-Term Debt to the Consolidated Financial Statements beginning on Page F-1 of this report for further discussion of the long-term debt classifications and the maturity dates and interest rates related to long-term debt.

New Accounting Standards

FASB Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations (FIN 47). In March 2005, the Financial Accounting Standards Board (FASB) published FIN 47, which requires companies to record a liability for those asset retirement obligations in which the timing or amount of settlement of the obligation are uncertain. These conditional obligations were not addressed by SFAS 143. FIN 47 will require us to accrue a liability when a range of scenarios can be determined. Management intends to adopt FIN 47 no later than the end of the fiscal year ending August 31, 2006, and has not yet determined the impact, if any, that this pronouncement will have on our financial statements.

SFAS No. 123 (Revised 2004) (SFAS 123R), Share-Based Payment. In December 2004, the FASB issued SFAS 123R, which replaces SFAS 123 and supercedes Accounting Principles Board (APB) Opinion No. 25. SFAS 123R requires an entity to recognize the grant-date fair-value of stock options and other equity-based compensation issued to employees in the income statement. The revised statement requires that an entity account for those transactions using the fair-value-based method, and eliminates the intrinsic value method of accounting in APB 25, *Accounting for Stock Issued to Employees*, which was permitted under SFAS No. 123 , as originally issued. The revised statement also requires entities to disclose information about the nature of the share-based payment transactions and the effects of those transactions on the financial statements. SFAS 123R is effective for public companies, that are not small business issuers, beginning with their next fiscal year. All public companies must use either the modified prospective or modified retrospective transition method. On March 29, 2005, the SEC staff issued SAB No. 107, Share-Based Payment, to express the views of the staff regarding the interaction between SFAS 123R and certain SEC rules and regulations and to provide the staff s views regarding the valuation of share-based payment arrangements for public companies. We have considered the additional guidance provided by SAB 107 in connection with our implementation of SFAS 123R as of September 1, 2005, which did not have a material impact on our consolidated results of operations, cash flows or financial position.

SFAS No. 151 (SFAS 151), Inventory Costs an amendment of ARB No. 43, Chapter 4. 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 we have determined that there are no other material items which require the application of SFAS 151.

SFAS No. 153 (SFAS 153), Exchanges of Nonmonetary Assets-an amendment of APB Opinion No. 29. In December 2004, the FASB issued SFAS 153, which amends APB Opinion No. 29 by eliminating the exception to the fair-value principle for exchanges of similar productive assets, which were accounted for under APB Opinion No. 29 based on the book value of the asset surrendered with no gain or loss recognition. SFAS 153 also eliminates APB 29 s concept of culmination of an earnings process. SFAS 153 is effective for nonmonetary transactions occurring in fiscal periods beginning after June 15, 2005. The impact of SFAS 153 will depend on the nature and extent of any exchanges of nonmonetary assets after the effective date, but management does not currently expect SFAS 153 to have a material impact on our consolidated results of operations, cash flows or financial position.

SFAS No. 154 (SFAS 154), Accounting Changes and Error Correction a replacement of APB Opinion No. 20 and FASB Statement No. 3. 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.

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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.

EITF Issue No. 03-13 (EITF 03-13), Applying the Conditions in Paragraph 42 of SFAS 144, Accounting for the Impairment or Disposal of Long-Lived Assets, in Determining Whether to Report Discontinued Operations. In November 2004, the EITF reached a consensus with respect to evaluating whether the criteria in SFAS 144 has been met for classifying as a discontinued operation a component of an entity that either has been disposed of or is classified as held for sale. To qualify as a discontinued operation, SFAS 144 requires that the cash flows of the disposed component be eliminated from the operations of the ongoing entity and that the ongoing entity not have any significant continuing involvement in the operations of the disposed component after the disposal transaction. The consensus is to be applied prospectively to a component of an entity that is either disposed or classified held for sale in fiscal periods beginning after December 15, 2004. We accounted for the sale of our discontinued operations in accordance with SFAS 144 and EITF 03-13 as of August 31, 2005.

EITF Issue No.04-1 (EITF 04-1). Accounting for Preexisting Relationships between the Parties to a Business Combination. EITF 04-1 requires that pre-existing contractual relationships between two parties involved in a business combination be evaluated to determine if a settlement of the pre-existing contracts is required separately from the accounting for the business combination. This consensus is effective for business combinations consummated and goodwill impairment tests performed in reporting periods beginning after October 13, 2004. We adopted EITF 04-1 during the quarter ended February 28, 2005, without a material effect on our financial position, results of operations and cash flows.

Critical Accounting Policies and 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. 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 Summary of Significant Accounting Policies and Balance Sheet Detail to the Consolidated Financial Statements beginning on page F-1 of this report. We believe the following are critical accounting policies:

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 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.

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

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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.

Primarily 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 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 No. 02-3), which requires revenue and costs related to energy trading contracts to be presented on a net basis in the income statement.

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. 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.

Stock Based Compensation Plans. We account for our stock compensation plans following the fair value recognition method. This method was adopted as we believe it is the preferable method of accounting for stock based compensation. Please see the caption Stock Based Compensation Plans in Note 3 Summary of Significant Accounting Policies and Balance Sheet Detail to the Consolidated Financial Statements beginning on page F-1 of this report for additional information about this adoption.

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.

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Amortization of Intangible Assets. 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 or asset values 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.

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 forward, future, swaps, options and certain basis contracts as cash flow hedging instruments. Certain contracts, which, in accordance with SFAS No. 133 Accounting for Derivative Instruments and Hedging Activities , are not accounted for as hedges, but are marked to fair value on the income statement. 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. On our contracts that are designated as cash flow hedging instruments 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 embedded derivatives. 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 receivable position of $1.9 million as of August 31, 2005, 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.

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 the 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 determined by dividing limited partners interest in net income by the weighted average number of Common 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. 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 Units outstanding and the weighted average number of restricted units (Unit Grants) granted under the Restricted Unit Plan

and the 2004 Unit Plan.

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.

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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 and 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 risk manager of our midstream and transportation and storage operations, sets forth risk management policies and objectives and 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 volatile 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, for storage both at our customer service locations and in major storage facilities and for future resale.

Non-trading activities

We use a combination of financial instruments including, but not limited to, futures, price swaps, options and basis trades 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 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 for 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 account for such physical contracts under the normal purchases and sales exception in accordance with 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 they 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 in the balance sheet as price risk management assets and liabilities measured at fair value. For those instruments 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 in cost of products sold. The fair value of price risk management assets and liabilities that are designated and 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) 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.

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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

During the fourth fiscal quarter of 2005, we adopted a new risk management policy that provides for our marketing operations to execute limited strategies. 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 futures and basis trades. 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 Issue No. 02-3, *Issues Related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities* (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. Physical contracts associated with the trading activities are accounted for on an accrual basis as they do not meet normal purchases and sales exception of SFAS 133.

Our price risk management assets and liabilities as of August 31, 2005 were as follows:

August 31, 2005:	Commodity	Notional Volume MMBTU	Maturity	Fair Value
Mark to Market Derivatives				
(Non-Trading)				
Basis Swaps IFERC/Nymex	Gas	(16,775,767)	2005	$ (5,462)
Basis Swaps IFERC/Nymex	Gas	(15,377,347)	2006	5,524
Basis Swaps IFERC/Nymex	Gas	(2,043,000)	2007	584
				$ 646
Swing Swaps IFERC	Gas	(11,986,504)	2005	(6,580)
Swing Swaps IFERC	Gas	(13,650,000)	2006	180
				$ (6,400)
Fixed Swaps/Futures	Gas	(2,150,000)	2005	$ (8,562)
Fixed Swaps/Futures	Gas	190,000	2006	1,139
				$ (7,423)
Options	Gas	416,000	2005	$ 17,552
Options	Gas	(730,000)	2006	46,951
Options	Gas	(730,000)	2007	15,772
Options	Gas	(732,000)	2008	(1,334)

				$ 78,941
Forward Physical Contracts	Gas	(5,578,000)	2005	$ (17,552)
Forward Physical Contracts	Gas	(10,730,000)	2006	(46,951)
Forward Physical Contracts	Gas	(4,300,000)	2007	(15,772)
Forward Physical Contracts	Gas	(732,000)	2008	1,334
				$ (78,941)
(Trading)				
Basis Swaps IFERC/Nymex	Gas	(24,917,500)	2005	$ 30,815
Basis Swaps IFERC/Nymex	Gas	(30,855,000)	2006	15,804
Basis Swaps IFERC/Nymex	Gas		2007	3,214
				$ 49,833
Swing Swaps IFERC	Gas	(26,345,000)	2005	$ (3,648)
Swing Swaps IFERC	Gas	(32,354,999)	2006	(52)
Swing Swaps IFERC	Gas	5,475,000	2007	14
Swing Swaps IFERC	Gas	11,020,000	2008	
				$ (3,686)
Fixed Swaps/Futures	Gas	(150,000)	2005	$ 559
Forward Physical Contracts	Gas		2005	$ 441
Cash Flow Hedging Derivatives				
Fixed Swaps/Futures	Gas	(28,930,000)	2005	$ (110,127)
Fixed Swaps/Futures	Gas	(13,137,500)	2006	(31,677)
Fixed Swaps/Futures	Gas	240,000	2007	662
				$ (141,142)
Fixed Index Swaps	Gas	2,640,000	2005	$ 15,628
Fixed Index Swaps	Gas	3,270,000	2006	20,827
				$ 36,455
Basis Swaps IFERC/Nymex	Gas	(6,412,500)	2005	$ 3,172
Basis Swaps IFERC/Nymex	Gas	(465,000)	2006	189
				$ 3,361

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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.

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 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

Interest Rate Risk

We are exposed to changes in interest rates, primarily as a result of our debt with floating interest rates 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, 2005, we had $252.6 million 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 $2.5 million in increased interest expense on an annual basis.

On January 6, 2005, we entered into a forward-starting interest swap with a notional amount of $300.0 million in anticipation of the bonds issued on January 18, 2005. The purpose of entering into this transaction was to effectively hedge the underlying U.S. Treasury rate related to our anticipated issuance of $750.0 million in principal amount of fixed rate debt. The settlement of the swap resulted in a loss of $0.4 million which is recorded in accumulated other comprehensive income. The loss will be amortized over the term of the bonds as interest expense.

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We also entered into various forward starting interest swaps from February 2005 through May 2005, in anticipation of the issuance of an additional bond offering in the third or fourth fiscal quarter of 2005. Due to certain market conditions, the bond offering was postponed until July 29, 2005. Such agreements were designated as cash flow hedges of an anticipated transaction under SFAS 133. When the forward starting interest swaps settle and the anticipated bonds are issued, the gain or loss from the swap will be amortized over the term of the bonds through interest expense. Certain forward starting interest swaps settled during the year ended August 31, 2005 with a net $1.9 million receipt from the counterparties. Due to the timing of entering into the forward starting interest swaps and the anticipated bond issuance, $2.4 million was recorded as a reduction of interest expense in the year ended August 31, 2005. Forward starting interest swaps with a notional amount of $150.0 million were outstanding as of August 31, 2005 and had a fair value of $2.2 million which was recorded as unrealized losses in accumulated other comprehensive income and a component of price risk management liabilities on the consolidated balance sheet. Ineffectiveness related to the forward starting interest swaps during the period was a loss of $0.9 million which was reclassified from accumulated other comprehensive income and recorded as a component of interest expense during the year ended August 31, 2005. A hypothetical change of 100 basis points on the underlying interest rates of the forward starting swaps outstanding at August 31, 2005 would have an effect of $12.2 million on the value of the swaps.

We also have an interest rate swap with a notional amount of $75.0 million that matured in October 2005 and had a fair value of $0.2 million as of August 31, 2005. Under the terms of the swap agreement, we will pay a fixed rate of 2.76% and will receive three-month LIBOR with a quarterly settlement. The interest rate swap is not accounted for as a hedge but receives mark to market accounting. Accordingly, changes in the fair value are recorded as a component of interest expense in the consolidated statement of operations. The interest rate swap is not subject to market fluctuation as the final rate reset occurred prior to August 31, 2005.

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.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

The financial statements set forth starting on page F-1 of this report are incorporated herein by reference.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

At the date of the Energy Transfer Transactions, Ernst & Young LLP was the independent auditor for ETC OLP, and Grant Thornton LLP was the independent auditor for Heritage. On February 3, 2004, our Audit Committee dismissed Ernst & Young LLP and appointed Grant Thornton LLP to serve as our independent auditors beginning in the fiscal year ending August 31, 2004. This matter was previously reported on Form 8-K dated February 4, 2004.

ETC OLP was formed on October 1, 2002, and Ernst & Young LLP rendered an audit opinion for the eleven-month period since inception to August 31, 2003. Ernst & Young LLP s report on ETC OLP s combined financial statements for the eleven months ended August 31, 2003 did not contain an adverse opinion or disclaimer of opinion, nor was such report qualified or modified as to uncertainty, audit scope or accounting principles. Since ETC OLP s inception and through the date of their dismissal, there have been: (i) no disagreements with Ernst & Young LLP on any matter of accounting principle or practice, financial statement disclosure or auditing scope or procedure which, if not resolved to Ernst & Young LLP s satisfaction, would have caused them to make reference to the subject matter in connection with their report on the combined financial statements for such period; and (ii) no reportable events as defined in Item 304(a)(1)(v) of Regulation S-K. During the fiscal year

ended August 31, 2005, ETC OLP s combined financial statements for the eleven months ended August 31, 2003 were re-audited by Grant Thornton LLP.

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Other than the above-described discussions, since ETC OLP s inception and through the date of Ernst & Young LLP s dismissal, ETC OLP did not consult with Grant Thornton LLP with respect to the application of accounting principles to a specified transaction, either completed or proposed, or the type of audit opinion that might be rendered on ETC OLP s financial statements, or any other matters or reportable events as set forth in Items 304(a)(2)(i) and (ii) of Regulation S-K.

ITEM 9A. CONTROLS AND PROCEDURES.

We maintain controls and procedures designed to ensure that information required to be disclosed in the reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. An evaluation was performed under the supervision and with the participation of our management, including the Co-Chief Executive Officers and Chief Financial Officer of our General Partner, of the effectiveness of the design and operation of our disclosure controls and procedures (as such terms are defined in Rule 13a 15(e) and 15d 15(e) of the Exchange Act). Based upon that evaluation, management, including the Co-Chief Executive Officers and Chief Financial Officer of our General Partner, concluded that our disclosure controls and procedures were adequate and effective as of August 31, 2005 to provide reasonable assurance that information required to be disclosed by us in the reports that we file to submit under the Exchange Act are recorded, processed, summarized and reported, within the time periods specified in the SEC s rules and forms.

Our management does not expect that our disclosure controls and procedures will prevent all errors and all fraud. The design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Based on the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the Company have been detected. These inherent limitations include the realties that judgments in decision-making can be faulty and that breakdowns can occur because of simple errors or mistakes. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the controls. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events. Therefore, a control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Our disclosure controls and procedures are designed to provide such reasonable assurances of achieving our desired control objectives and the Co-Chief Executive Officers of our General Partner and the Chief Financial Officer of our General Partner have concluded, as of August 31, 2005, that our disclosure controls and procedures are effective in achieving that level of reasonable assurance.

Management s Report on Internal Controls Over Financial Reporting

The management of Energy Transfer Partners, L.P. and subsidiaries is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13A-15(f). Under the supervision and with the participation of our management, including the Co-Chief Executive Officers of our General Partner, and Chief Financial Officer of our General Partner, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO framework). In conducting our evaluation of the effectiveness of our internal control over financial reporting, we have excluded the acquisition of HPL Consolidation, L.P. in January 2005 due to its size and complexity. Collectively, this acquisition constituted 31% of total assets as of August 31, 2005, 38% of total revenues and 4% of net income for the year then ended. Such exclusion was in accordance with Securities and Exchange Commission guidance that an assessment of a recently acquired business may be omitted in management s report on internal controls over financial reporting, provided the acquisition took place within twelve months of management s evaluation. See further discussion below. Based on our evaluation under the COSO framework, our management concluded that our internal control over financial reporting was effective as of August 31, 2005.

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Our management s assessment of the effectiveness of our internal control over financial reporting as of August 31, 2005, has been audited by Grant Thornton LLP, an independent registered public accounting firm, as stated in their report which is included herein.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Partners

Energy Transfer Partners, L.P.

We have audited management s assessment, included in the accompanying Management s Report on Internal Control over Financial Reporting (Management s Assessment), that Energy Transfer Partners, L.P. (a Delaware limited partnership) and subsidiaries (collectively, the Partnership) maintained effective internal control over financial reporting as of August 31, 2005, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Partnership s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management s assessment and an opinion on the effectiveness of the Partnership s internal control over financial reporting based on our audit.

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

As indicated in Management s Assessment, management s assessment of and conclusion on the effectiveness of internal control over financial reporting did not include an assessment of the effectiveness of internal controls over financial reporting of HPL Consolidation LP (HPL). HPL was acquired on January 26, 2005 and has been included in the consolidated financial statements of the Partnership since that date. HPL constituted approximately 31% of total assets as of August 31, 2005 and 38% of revenues and 4% of net income for the year then ended. Our audit of internal control over financial reporting of the Partnership also did not include an evaluation of the internal controls over financial reporting of HPL.

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

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

In our opinion, management s assessment that Energy Transfer Partners, L.P. maintained effective internal control over financial reporting as of August 31, 2005, is fairly stated, in all material respects, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Also in our opinion, Energy Transfer Partners,

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L.P. maintained, in all material respects, effective internal control over financial reporting as of August 31, 2005, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Energy Transfer Partners, L.P. and subsidiaries, as of August 31, 2005 and 2004, and the related consolidated statements of operations, comprehensive income, partners capital, and cash flows for each of the two years in the period ended August 31, 2005 and for the eleven months ended August 31, 2003 and our report dated November 8, 2005 expressed an unqualified opinion on those consolidated financial statements.

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma

November 8, 2005

Changes in Internal Control Over Financial Reporting

There have been no changes in our internal controls over financial reporting (as defined in Rule 13(a) 15f or Rule 15d 15(f) of the Exchange Act) during three months ended August 31, 2005 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting, except for the HPL acquisition discussed below.

HPL acquisition

On January 26, 2005, we completed the HPL acquisition. In recording the HPL acquisition, we followed our normal accounting procedures and internal controls. Our management also reviewed the operations of the HPL System from the date of the acquisition that are included in our earnings for the fiscal year ended August 31, 2005. In addition, we solicited disclosure information from former AEP (now ETC OLP) employees and reviewed the historical audited financial statements and notes accompanying the financial statements. We are continuing to integrate our internal controls into these operations, and it is expected that this effort will continue into future fiscal quarters of 2006. As described below, HPL s business has been excluded from our fiscal 2005 internal control assessment.

We have excluded HPL s business from our internal control assessment for the following reasons:

The procedure established by AEP for prospective buyers of the HPL System limited the evaluation period to a fairly short time frame. This severely limited our ability to conduct a timely and specific due diligence review of HPL s existing internal control framework. Given the time required to test the operating effectiveness of such controls and the due date for our Section 404 attestation, it was not practical from a timing or resource standpoint for us to conduct a thorough assessment prior to our 2005 fiscal year end;

HPL s business utilized a financial accounting computer system (i.e., general ledger system) and other industry-specific computer applications that are different from those used by us through August 31, 2005. For various reasons, HPL s business remained on these systems (which were on the computer network of AEP) through the end of fiscal year 2005, but have been fully converted to our financial accounting computer system (and computer network) during the first fiscal quarter of 2006. As a result, we believe that reporting on the controls of the current computer system used by HPL will not be useful to our investors since these systems will not be utilized soon after August 31, 2005.

We will continue to evaluate HPL s business and are making various changes to its operating and organizational structure based on our business plan which is substantially different from AEP s business plan. We are in the process of implementing our internal control structure over the operations of HPL. We expect that this effort will continue into future fiscal quarters of 2006 due to the magnitude of the business. The assessment and documentation of internal controls requires a complete implementation of controls operating in a stable and effective environment.

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ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT.

Partnership Management

ETP GP (the General Partner) is our General Partner. The General Partner manages and directs all of our activities. The activities of the General Partner are managed and directed by its general partner, ETP LLC. Our officers and directors are officers and directors of ETP LLC. The owners of the General Partner and ETP LLC may appoint up to eleven persons at least three of whom qualify as independent directors to serve on ETP LLC s Board of Directors. In addition, persons serving as ETP LLC s Chairman, President or Chief Executive Officer also serve on ETP LLC s Board of Directors. Each of these persons is individually a manager of ETP LLC, and are collectively referred to as our Board of Directors.

In connection with the Energy Transfer Transactions in January 2004, the former owners of the General Partner sold all of their ownership interests in the General Partner and ETP LLC to ETE (the General Partner Transaction). The eight members of the Board of Directors that had been previously designated by the four member/owners of ETP LLC and the former Chairman resigned at the time of the General Partner Transaction. The three independent members and ETP LLC s President remained on the Board of Directors, and additional members were elected to the Board of Directors by ETE.

At all times during the Partnership s 2005 fiscal year, our Board of Directors was comprised of its two Co-Chairmen, ETP LLC s President, four persons who qualify as independent under the NYSE s standards for audit committee members, and five persons elected by the other members of the Board of Directors. At the October 10, 2005 meeting of our Board of Directors, two of our directors, Stephen L. Cropper and J. Charles Sawyer, did not stand for reelection. Additional directors will be appointed to the Board of Directors by ETE, including at least one person who qualifies as independent under the NYSE s standards for audit committee members.

Corporate Governance

The Board of Directors of our General Partner has adopted both a Code of Business Conduct applicable to our Directors, Officers and Employees, and Corporate Governance Guidelines for Directors and the Board. Current copies of our Code of Business Conduct, Corporate Governance Guidelines and charters applicable to the committees of our Board of Directors are available on our website at www.energytransfer.com and will be provided in print form to any Common Unitholder requesting such information.

Annual Certification

We have filed the required certifications under Section 302 of the Sarbanes-Oxley Act of 2002 as Exhibits 31.1 and 31.2 to this report. In fiscal year 2005, our Co-Chief Executive Officers provided to the New York Stock Exchange the annual CEO certification regarding our compliance with the New York Stock Exchange s corporate governance listing standards.

Independent Committee

The Board of Directors appoints members of the Board to serve on the Independent Committee with the authority to review specific matters for which the Board of Directors believes there may be a conflict of interest in order to determine if the resolution of such conflict proposed by the General Partner is fair and reasonable to the Partnership and its Common Unitholders. Any matters approved by the Independent Committee will be conclusively deemed to be fair and reasonable to the Partnership, approved by all partners of the Partnership and not a breach by the General Partner or its Board of Directors of any duties they may owe the Partnership or the Common

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Unitholders. Bill W. Byrne, Stephen L. Cropper, and J. Charles Sawyer served as the members of the Independent Committee of the Board of Directors from the time of their appointment in October 2002 until February 2004. In February 2004, Stephen L. Cropper and Paul E. Glaske were appointed as members of the Independent Committee. At the October 2005 meeting of the Board of Directors, Paul E. Glaske was re-elected as a member of the Independent Committee.

Audit Committee

The Board of Directors has established an Audit Committee in accordance with Section 3(a)(58)(A) of the Exchange Act. The Board of Directors appoints persons who are independent under the NYSE s standards for audit committee members to serve on its Audit Committee. In addition, the Board determines that at least one member of the Audit Committee has such accounting or related financial management expertise sufficient to qualify such person as the audit committee financial expert in accordance with Item 401 of Regulation S-K. The Board has determined that based on relevant experience, Audit Committee member Stephen L. Cropper qualified as an Audit Committee financial expert during the Partnership s 2005 fiscal year. At the October 2005 meeting of the Board of Directors, the Board determined that Audit Committee member Paul E. Glaske qualified as an Audit Committee financial expert based upon his relevant experience. A description of the qualifications of both Messr. Cropper and Messr. Glaske may be found elsewhere in this Item 10 under Directors and Executive Officers of the General Partner.

The Audit Committee meets on a regularly scheduled basis with our independent accountants at least four times each year and is available to meet at their request. The Audit Committee has the authority and responsibility to review our external financial reporting, review our procedures for internal auditing and the adequacy of our internal accounting controls, consider the qualifications and independence of our independent accountants, engage and direct our independent accountants, including the letter of engagement and statement of fees relating to the scope of the annual audit work and special audit work which may be recommended or required by the independent accountants, and to engage the services of any other advisors and accountants as the Audit Committee deems advisable. The Audit Committee reviews and discusses the audited financial statements with management, discusses with our independent auditors matters required to be discussed by SAS 61, *Communications with Audit Committees,* and makes recommendations to the Board of Directors relating to our audited financial statements. The Audit Committee periodically recommends to the Board of Directors any changes or modifications to its charter that may be required. The Board of Directors adopts the Charter for the Audit Committee. Bill W. Byrne, Stephen L. Cropper, and J. Charles Sawyer have served as members of the Audit Committee of the Board of Directors since their appointment in February 2002. In February 2004, Paul E. Glaske was appointed as the fourth member and Chairman of the Audit Committee. Messrs. Byrne, Cropper, Sawyer and Glaske were reappointed to serve on the Audit Committee in October 2004, and Messr. Glaske was reappointed as its Chairman. At the October 2005 meeting of the Board of Directors, Messrs. Byrne and Glaske were reappointed to serve on the Audit Committee.

Compensation and Nominating/Corporate Governance Committees

Although we are not required under NYSE rules to appoint a Compensation Committee or a Nominating/Corporate Governance Committee because we are a limited partnership, the Board of Directors of ETP LLC has established a Compensation Committee to establish standards and make recommendations concerning the compensation of our officers and directors. In addition, the Compensation Committee determines and establishes the standards for any awards to our employees and officers under the equity compensation plans adopted by our Common Unitholders, including the performance standards or other restrictions pertaining to the vesting of any such awards. A director serving as a member of the Compensation Committee may not be an officer of or employed by the General Partner, the Partnership or its subsidiaries. Stephen L. Cropper, Bill W. Byrne and K. Rick Turner were appointed to serve as the members of the Compensation Committee in February 2004, and Messr. Turner was appointed as its Chairman. At the October 2005 meeting of the Board of Directors, Messr. Byrne was reappointed to serve on the Compensation Committee, and Messr. Turner was reappointed as its Chairman.

Matters relating to the nomination of Directors or Corporate Governance matters are addressed to and determined by the full Board of Directors.

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Code of Business Conduct

The Board of Directors has adopted a Code of Business Conduct applicable to our officers, directors and employees. Specific provisions are applicable to the principal executive officer, principal financial officer, principal accounting officer and controller, or those persons performing similar functions, of our General Partner. The Code of Business Conduct is available on our website at www.energytransfer.com and in print to any Unitholder that requests and it. Amendments to, or waivers from, the Code of Business Conduct will also be available on our website and reported as may be required under SEC rules, however, any technical, administrative or other non-substantive amendments to the Code of Business Conduct may not be posted. Please note that the preceding Internet address is for information purposes only and is not intended to be a hyperlink. Accordingly, no information found and/or provided at such Internet addresses or at our website in general is intended or deemed to be incorporated by reference herein.

Meetings of Non-management Directors and Communications with Directors

Our non-management Directors meet in regularly scheduled sessions. The Chairman of each of the Partnership s Audit, Independent and Compensation Committees alternate as the presiding director of such meetings.

The Partnership has established a procedure by which Unitholders may communicate directly with the Board of Directors, any committee of the Board, any of the Partnership s independent directors, or any one director serving on the Board of Directors by sending written correspondence addressed to the desired person or entity to the attention of the Partnership s General Counsel at Energy Transfer Partners, L.P., 8801 South Yale Avenue, Suite 310, Tulsa, Oklahoma 74137 or generalcounsel@energytransfer.com. Communications are distributed to the Board of Directors, or to any individual director or directors as appropriate, depending on the facts and circumstances outlined in the communication.

Directors and Executive Officers of the General Partner

The following table sets forth certain information with respect to the executive officers and members of the Board of Directors as of October 9, 2005. Executive officers and directors are elected for one-year terms.

Name	Age	Position with General Partner
Ray C. Davis	63	Co-Chief Executive Officer and Co-Chairman of the Board of Directors of the General Partner
Kelcy L. Warren	50	Co-Chief Executive Officer and Co-Chairman of the Board of Directors of the General Partner
H. Michael Krimbill	52	President, Chief Financial Officer and Director of the General Partner
R.C. Mills	67	Executive Vice President and Chief Operating Officer
Mackie McCrea	46	Senior Vice President Commercial Development
Bradley K. Atkinson	50	Vice President Corporate Development
Robert A. Burk	48	Vice President and General Counsel and Secretary
John W. Daigh (1)	50	Vice President and Treasurer

Karen Z. Hicks (2)	43	Vice President of Administration and Controller
Stephen L. Cropper (3)	55	Director of the General Partner

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Name	Age	Position with General Partner
Bill W. Byrne	75	Director of the General Partner
J. Charles Sawyer (3)	69	Director of the General Partner
David R. Albin	46	Director of the General Partner
Kenneth A. Hersh	42	Director of the General Partner
Paul E. Glaske	72	Director of the General Partner
K. Rick Turner	47	Director of the General Partner
Ted Collins, Jr.	67	Director of the General Partner
John W. McReynolds	54	Director of the General Partner

(1) Elected Vice President and Treasurer September 2004.
(2) Elected Vice President of Administration September 2004.
(3) This Director did not stand for reelection at the October 2005 meeting of the Board of Directors of our General Partner.

Set forth below is biographical information regarding the foregoing officers and directors of our General Partner:

Ray C. Davis. Mr. Davis is Co-Chief Executive Officer and Co-Chairman of the Board of Directors of our General Partner and has served in that capacity since the combination of the midstream and transportation and storage operations of ETC OLP and the retail propane operations of HOLP in January 2004. Mr. Davis also serves as Co-Chairman of the Board of Directors of the general partner of ETE, a position he has held since October of 2002. Prior to the combination of the operations of ETC OLP and HOLP, Mr. Davis served as Vice President of the general partner of ET Company I, Ltd., the entity that operated ETC OLP s midstream assets before it acquired Aquila, Inc. s midstream assets, having served in that capacity since 1996. From 1996 to 2000, he served as a Director of Crosstex Energy, Inc. From 1993 to 1996, he served as Chairman of the board of directors and Chief Executive Officer of Cornerstone Natural Gas, Inc. Mr. Davis has more than 31 years of business experience in the energy industry.

Kelcy L. Warren. Mr. Warren is the Co-Chief Executive Officer and Co-Chairman of the Board of our General Partner and has served in that capacity since the combination of the midstream and transportation and storage operations of ETC OLP and the retail propane operations of HOLP in January 2004. Mr. Warren also serves as Co-Chairman of the Board of Directors of the general partner of ETE, a position he has held since October 2002. Prior to the combination of the operations of ETC OLP and HOLP, Mr. Warren served as President of the general partner of ET Company I, Ltd., having served in that capacity since 1996. From 1996 to 2000, he served as a director of Crosstex Energy, Inc. From 1993 to 1996, he served as President, Chief Operating Officer and a director of Cornerstone Natural Gas, Inc. Mr. Warren has more than 20 years of business experience in the energy industry

H. Michael Krimbill. Mr. Krimbill is the President and Chief Financial Officer of our General Partner, and has served in these capacities since January 2004. Mr. Krimbill joined Heritage as Vice President and Chief Financial Officer in 1990. He served as President of Heritage from April 1999 to January 2004 and as President and Chief Executive Officer of Heritage from March 2000 to January 2004. Mr. Krimbill has served as a director of our General Partner since his election in August 2000.

R.C. Mills. Mr. Mills is the Executive Vice President and Chief Operating Officer of our General Partner, and has served in these capacities since January 2004. In March 2005, Mr. Mills was named President of HOLP. Mr. Mills has over 40 years of experience in the propane industry. Mr. Mills joined Heritage in 1991 as Executive Vice President and Chief Operating Officer. Before coming to Heritage, Mr. Mills spent 25 years with Texgas Corporation in various capacities, including as the Executive Vice President and Chief Operations Officer.

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Mackie McCrea. Mr. McCrea is the Senior Vice President Commercial Development of our General Partner and has served in that capacity since the combination of the operations of ETC OLP and HOLP in January 2004. In March 2005, Mr. McCrea was named president of ETC OLP. Prior to the combination of the operations of ETC OLP and HOLP, Mr. McCrea served as Senior Vice President Business Development and Producer Services of the general partner of ETC OLP and ET Company I, Ltd., having served in that capacity since 1997.

Bradley K. Atkinson. Mr. Atkinson is Vice President Corporate Development of our General Partner and has served in that capacity since August 2000. Mr. Atkinson joined Heritage on April 16, 1998 as Vice President of Administration. Prior to joining Heritage, Mr. Atkinson spent 12 years with MAPCO/ Thermogas, eight of which were spent in the acquisitions and business development of Thermogas.

Robert A. Burk. Mr. Burk is Vice President General Counsel and Secretary of our General Partner and has served in that capacity since February 2004. Prior to joining ETP, Mr. Burk was a partner in the law firm of Doerner, Sanders, Daniel & Anderson, LLP, which served as outside counsel to Heritage since shortly after its formation and prior to its initial public offering in 1996.

John W. Daigh. Mr. Daigh is Vice President and Treasurer of our General Partner and has served in that capacity since September 2004. Mr. Daigh joined ETP in October 2002, serving as ETC OLP s Vice President and Controller until assuming his current role as Vice President and Treasurer. Mr. Daigh served as Vice President of Economics at Aquila, Inc. from 1999 until the time that ETP acquired its assets in 2002. Mr. Daigh also served in various controller and management roles at Koch Industries, Inc. prior to his joining Aquila, Inc. in 1999.

Karen Z. Hicks. Ms. Hicks is Vice President of Administration and Controller of our General Partner, serving in that capacity since September 2004 and has served as Controller of our General Partner since July 2002. Ms. Hicks has spent 17 years in the propane industry, all of which have been with Energy Transfer and Heritage. Ms. Hicks started her career with Heritage as Accounting Manager and was promoted to Manager of Financial Reporting when the Partnership went public in 1996. In December 2000, Ms. Hicks was promoted to Assistant Controller and was promoted to Partnership Controller July 2002. Prior to her career in the propane industry, Ms. Hicks was a bank examiner for the State of Montana for three years.

Stephen L. Cropper. Mr. Cropper spent 25 years with The Williams Companies before retiring in 1998, as President and Chief Executive Officer of Williams Energy Services. Mr. Cropper is a director of NRG Energy, Inc. where he serves as the Chairman of the Corporate Governance and Nominating Committee. Mr. Cropper also serves as a director, Chairman of the Audit Committee, and member of the Compensation Committee of Sun Logistics Partners L.P. Mr. Cropper is a director and serves as the Chairman and an Audit Committee financial expert of Berry Petroleum Company. Mr. Cropper is a director of Rental Car Finance Corporation, a subsidiary of Dollar Thrifty Automotive Group. Mr. Cropper is also a director and serves as the Chairman of the Compensation Committee and a member of the Audit Committee and Executive Committee of QuikTrip Corporation. Mr. Cropper has served as a director of our General Partner since April 2000 and is a member of the Independent Committee, the Litigation Committee, the Compensation Committee, and the Audit Committee. Mr. Cropper did not stand for reelection at the October 2005 meeting of the Board of Directors of our General Partner.

Bill W. Byrne. Mr. Byrne is the principal of Byrne & Associates, LLC, a gas liquids consulting group based in Tulsa, Oklahoma, and has held that position since 1992. Prior to that time, he served as Vice President of Warren Petroleum Company, the gas liquids division of Chevron Corporation, from 1982 to 1992. Mr. Byrne has served as a director of our General Partner since 1992 and is a member of both the Audit Committee and the Compensation Committee. Mr. Byrne is a former president and director of the National Propane Gas Association (NPGA).

J. Charles Sawyer. Mr. Sawyer is the President and Chief Executive Officer of Sawyer Cellars. Mr. Sawyer is also the President and Chief Executive Officer of Computer Energy, Inc., a provider of computer software to the propane industry since 1981. Mr. Sawyer was Chief

Executive Officer of Sawyer Gas Co., a regional propane distributor, until it was purchased by Heritage in 1991. Mr. Sawyer is a former president and director of the NPGA. Mr. Sawyer has served as a director of our General Partner since 1991 and is a member of both the Independent Committee and the Audit Committee. Mr. Sawyer did not stand for reelection at the October 2005 meeting of the Board of Directors of our General Partner.

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David R. Albin. Mr. Albin is a managing partner of Natural Gas Partners, L.L.C. and has served in that capacity or similar capacities since 1988. Prior to his participation as a founding member of Natural Gas Partners, L.P. in 1988, he was a partner in the $600 million Bass Investment Limited Partnership. Prior to joining Bass Investment Limited Partnership, he was a member of the oil and gas group in the investment banking division of Goldman, Sachs & Co. He currently serves as a director of NGP Capital Resources Company. Mr. Albin has served as a director of our General Partner since February 2004.

Kenneth A. Hersh. Mr. Hersh is a managing partner of Natural Gas Partners, L.L.C. and has served in that capacity or similar capacities since 1989. Prior to joining Natural Gas Partners, L.P. in 1989, he was a member of the energy group in the investment banking division of Morgan Stanley & Co. He currently serves as a director of NGP Capital Resources Company. Mr. Hersh has served as a director of our General Partner since February 2004.

Paul E. Glaske. Mr. Glaske retired as Chairman and Chief Executive Officer of Blue Bird Corporation, the largest manufacturer of school buses with manufacturing plants in three countries. Prior to becoming president of Blue Bird in 1986, Mr. Glaske served as the president of the Marathon LeTourneau Company, a manufacturer of large off-road mining and material handling equipment and off-shore drilling rigs. He currently is a member of the board of directors of the Texas Association of Business; SunTrust Bank, Middle Georgia, N.A.; Borg Warner Automotive, Inc.; and the U.S. Chamber of Commerce. Mr. Glaske has served as a director of our General Partner since February 2004 and is chairman of the Audit Committee and a member of the Independent Committee. In addition, Mr. Glaske serves as the Vice-Chairman of the Natural Gas Vehicle Coalition.

K. Rick Turner. Mr. Turner joined Stephens Group, Inc. in 1983 and had been a Principal of its private equity group since 1990. Stephens Group, Inc., is the parent company of Stephens, Inc., one of the largest off-Wall Street investment banking groups, since 1990. Mr. Turner s areas of focus have been oil and gas exploration, natural gas gathering, processing industries, and power technology. He currently serves as a director of Atlantic Oil Corporation; SmartSignal Corporation; JV Industrial Companies, Ltd., JEBCO Seismic, LLC; and North American Energy Partners Inc. Mr. Turner has served as a director of the general partner of ETE since October 2002. Mr. Turner has served as a director of our General Partner since February 2004 and serves as the chairman of the Compensation Committee.

Ted Collins, Jr. Mr. Collins has been an independent oil and gas producer since 2000. Mr. Collins previously served as President of Collins & Ware Inc. from 1988 to 2000, when its assets were sold to Apache Corporation. From 1982 to 1988, Mr. Collins was President of Enron Oil and Gas Company, and its predecessors, HNG Oil Company and HNG Internorth Exploration Co. From 1969 to 1982, Mr. Collins served as Executive Vice President of American Quaser Petroleum Company. Mr. Collins is a director and serves on the Finance Committee of Hanover Compression Company, and is a director and the Chairman of the Governance Committee of Encore Acquisition Company. Mr. Collins has served as a director of our General Partner since August 2004.

John W. McReynolds. Mr. McReynolds is a director, and the President and Chief Financial Officer of Energy Transfer Equity, L.P. (ETE). Mr. McReynolds has served as the President of ETE since March 2005, and as a director and the Chief Financial Officer of ETE since August 2005. Prior to becoming President of ETE, Mr. McReynolds was a partner with the international law firm of Hunton & Williams LLP for over 20 years. As a lawyer, he specialized in energy-related finance, securities, partnerships, mergers and acquisitions, syndication and litigation matters, and served as an expert in numerous arbitration, litigation and government proceedings, including as an expert in special projects for boards of directors of public companies. Mr. McReynolds has served a director of our General Partner since August 2004.

Compensation of the General Partner

ETP GP does not receive any management fee or other compensation in connection with its management of the Partnership and the Operating Partnerships. ETP GP and its affiliates performing services for the Partnership and the Operating Partnerships are reimbursed at cost for all expenses incurred on behalf of the Partnership, including the costs of employee compensation allocable to Heritage, and all other expenses necessary or appropriate to the conduct of the business of, and allocable to, the Partnership. Following the Energy Transfer Transactions in January 2004, the employees of the General Partner became employees of our Operating Partnerships, and thus, the ETP GP has not incurred additional reimbursable costs since that time.

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Compliance with Section 16(a) of the Securities and Exchange Act

Section 16(a) of the Securities and Exchange Act of 1934 requires our officers and directors, and persons who own more than 10% of a registered class of our equity securities, to file reports of beneficial ownership and changes in beneficial ownership with the Securities and Exchange Commission (SEC). Officers, directors and greater than 10% Unitholders are required by SEC regulations to furnish the General Partner with copies of all Section 16(a) forms.

Based solely on our review of the copies of such forms received by us, or written representations from certain reporting persons that no Forms 5 were required for those persons, we believe that during fiscal year ending August 31, 2005, all filing requirements applicable to its officers, directors, and greater than 10% beneficial owners were met in a timely manner, other than one late Form 4 filing for each of R.C. Mills, Rick Turner and Ted Collins, Jr.

ITEM 11. EXECUTIVE COMPENSATION.

We do not directly employ any of the persons responsible for managing or operating our business. Instead, we are managed by ETP GP and its executive officers.

The following table sets forth the annual salary, bonus and all other compensation awards and payouts for each of the past three fiscal years earned by: (i) all persons serving as the Chief Executive Officer of ETP GP during fiscal year 2005; (ii) the four next highly compensated executive officers other than the Chief Executive Officer, who served as executive officers of ETP GP during fiscal year 2005 and (iii) any persons who would have been reported had they been an executive officer of our ETP GP at the end of fiscal year 2005.

Name and Principal Position	Year	Salary	Bonus (3)	Other Annual Compensation (4)	All Other Compensation (5)
Ray C. Davis Co-Chief Executive Officer (1)	2005 2004 2003	$ 443,462 120,000	$ 500,000	$ 1,584 172	$
Kelcy L. Warren Co-Chief Executive Officer (1)	2005 2004 2003	$ 425,000 120,000	$ 500,000	$ 552 172	$
H. Michael Krimbill President and Chief Financial Officer (2)	2005 2004 2003	$ 350,000 350,000 350,000	$ 300,000 609,000 60,000	$ 372 372 325	$ 1,321,240 356,878
R. C. Mills Executive Vice President and Chief Operating Officer	2005 2004 2003	$ 335,000 335,000 335,000	$ 100,000 594,000 60,000	$ 2,052 2,052 2,052	$ 1,321,240 356,878
Mackie McCrea Senior Vice President Commercial Development	2005 2004 2003	$ 310,923 183,042	$ 174,000 248,000	$ 360 186	$

Robert A. Burk (6)	2005	$ 226,538	$ 70,000	$ 160	$
Vice President General	2004	200,000		145	
Counsel and Secretary	2003				

(1) Messrs Davis and Warren were named Co-Chief Executive Officers of our General Partner in January of 2004.

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(2) Mr. Krimbill served as President and Chief Executive Officer of our General Partner until January 2004. After the Energy Transfer Transactions, Mr. Krimbill was elected President and Chief Financial Officer of ETP GP.
(3) Bonuses are earned based on the results of operations for each fiscal year. Bonuses for the 2004 fiscal year for Messrs. Krimbill and Mills also include payments for the termination of their employment contracts in connection with the Energy Transfer Transactions.
(4) Consists of life insurance premiums.
(5) Consists of the value of Common Units issued pursuant to awards under the Long-Term Incentive Compensation Plan, which terminated in conjunction with the Energy Transfer Transactions.
(6) Mr. Burk was named Vice President General Counsel of our General Partner in February of 2004. Mr. Burk s 2004 salary is annualized.

Restricted Unit Plan

We previously adopted the Amended and Restated Restricted Unit Plan dated August 10, 2000, and amended February 4, 2002 as the Second Amended and Restated Restricted Unit Plan (the Restricted Unit Plan), copies of which have been previously filed as exhibits, for certain directors and key employees of the General Partner and its affiliates. The Restricted Unit Plan provided rights to acquire up to 292,000 Common Units. The Restricted Unit Plan provided for the award or grant to key employees of the right to acquire Common Units on such terms and conditions (including vesting conditions, forfeiture or lapse of rights) as the Compensation Committee of the General Partner shall determine. In addition, eligible directors automatically received a director s grant of to 1,000 Common Units on each September 1, and newly elected directors were also entitled to receive a grant of 2,000 Common Units upon election or appointment to the Board. Directors who were our employees or employees of our General Partner were not entitled to receive a director s grant of Common Units but could receive Common Units as employees.

Generally, awards granted under the Restricted Unit Plan vested upon the occurrence of specified performance objectives established by the Compensation Committee at the time designations of grants were made, or if later, the three-year anniversary of the grant date. In the event of a change of control (as defined in the Restricted Unit Plan), all rights to acquire Common Units pursuant to the Restricted Unit Plan immediately vested. In connection with ETE s acquisition of our General Partner in January of 2004, all of the previous awards under the Restricted Unit Plan, except for awards for which waivers were granted thereunder or in conjunction with the employment agreement of the former Chairman of our General Partner, vested.

The issuance of Common Units pursuant to the Restricted Unit Plan was intended to serve as a means of incentive compensation, therefore, no consideration was payable by the plan participants upon vesting and issuance of the Common Units. During fiscal year 2005, 4,333 units vested under the Restricted Unit Plan and Common Units were issued. As of August 31, 2005, 12,259 units have been awarded and have not yet vested. On September 1, 2005, an additional 3,000 units vested under the Restricted Unit Plan, and Common Units were issued. Following the June 23, 2004 approval of the 2004 Unit Plan at a Special Meeting of the Unitholders, the Restricted Unit Plan was terminated (except for the obligation to issue Common Units at the time the Units previously awarded vest), and no additional grants have been or will be made under the Restricted Unit Plan.

Long-Term Incentive Compensation Plan

Effective September 1, 2000, we adopted a long-term incentive compensation plan whereby units were to be awarded to the executive officers of our General Partner upon achieving certain targeted levels of Distributed Cash (as defined in the Long-Term Incentive Plan) per unit. Awards under the program were made starting in 2003 based upon the average of the prior three years Distributed Cash per unit. A minimum of 500,000 units on a post-split basis and, if targeted levels were achieved, a maximum of 1,000,000 units were available for award under the Long-Term Incentive Plan. Awards under the program were made starting in 2003 based upon the average of the prior three years Distributed Cash per unit. During the fiscal year ended August 31, 2003, 132,236 units vested pursuant

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to the vesting rights of the Long-Term Incentive Plan and Common Units were issued. In connection with the acquisition by ETE of our General Partner in January 2004, 300,036 units vested and Common Units were issued, and the Long-Term Incentive Plan terminated. Heritage recognized compensation expense of $0.6 million, and $0.9 million for fiscal years 2004, and 2003, respectively.

2004 Unit Plan

On June 23, 2004, at a special meeting of the Common Unitholders, our Common Unitholders approved the terms of our 2004 Unit Plan (the Plan), which provides for awards of Common Units and other rights to our employees, officers, and directors and is filed as an exhibit to this Form 10-K. The maximum number of Common Units that may be granted under this Plan is 1,800,000 net units issued. Any awards that are forfeited or which expire for any reason or any units which are not used in the settlement of an award will be available for re-grant under the Plan. Units to be delivered upon the vesting of awards granted under the Plan may be (i) units acquired by us in the open market, (ii) units already owned by us or our General Partner, (iii) units acquired by us or our General Partner directly from the Partnership, or any other person, (iv) units that are registered under a registration statement for this Plan, (v) Restricted Units, or (vi) any combination of the foregoing.

Employee Grants. The Compensation Committee, in its discretion, may from time to time grant awards to any employee, upon such terms and conditions as it may determine appropriate and in accordance with specific general guidelines as defined by the Plan. All outstanding awards shall fully vest into units upon any change in control as defined by the Plan, or upon such terms as the Compensation Committee may require at the time the award is granted. During fiscal 2005, awards totaling 273,200 units were made under the 2004 Unit Plan to employees, including executive officers, and 7,600 awards were forfeited. These awards will vest over a three-year period based upon the achievement of certain performance criteria. Vested awards will convert into Common Units upon the third anniversary of the measuring date for the grants, which is September 1 of each year. Vesting occurs based upon the total return to our Unitholders as compared to a group of our peers.

Director Grants. Each director who is not also (i) a shareholder or a direct or indirect employee of any parent, or (ii) a direct or indirect employee of Energy Transfer Partners, LLC, the Partnership or a subsidiary (Director Participant), who is elected or appointed to the Board for the first time shall automatically receive, on the date of his or her election or appointment, an award of up to 2,000 units (the Initial Director s Grant). Commencing on September 1, 2004 and each September 1 thereafter that this Plan is in effect, each Director Participant who is in office on such September 1, shall automatically receive an award of units equal to $15,000 divided by the fair market value of a Common Units on such date (Annual Director s Grant). Each grant of an award to a Director Participant will vest at the rate of 1/3 per year, beginning on the first anniversary date of the Award; provided however, notwithstanding the foregoing, (i) all awards to a Director Participant shall become fully vested upon a change in control , as defined by the Plan, unless voluntarily waived by such Director Participant, and (ii) all awards which have not yet vested on the date a Director Participant ceases to be a director shall vest on such terms as may be determined by the Compensation Committee. As of August 31, 2005, Initial Director s Grants totaling 12,000 units and annual grants totaling 4,844 units have been made. On August 31, 2005, 3,999 Initial Director Grants vested and on September 1, 2005, 1,610 Annual Director Grants vested and Common Units were issued. Also on September 1, 2005, Annual Director Grants totaling 2,460 units were made.

Long-Term Incentive Grants. The Compensation Committee may, from time to time, grant awards under the Plan to any executive officer or any employee it designates as a participant in accordance with general guidelines under the Plan. These guidelines include (i) options to purchase a specified number of units at a specified exercise price, which are clearly designated in the award as either an incentive stock option within the meaning of Section 422 of the Internal Revenue Code, or a non-qualifying stock option that is not intended to qualify as an incentive stock option under Section 422; (ii) Unit Appreciation Rights that specify the terms of the fair market value of the award on the date the stock appreciation right is exercised and the strike price; (iii) units; or (iv) any combination hereof. As of August 31, 2005, there have been no such grants awarded under the 2004 Unit Plan.

The 2004 Unit Plan is administered by the Compensation Committee of the Board of Directors and may be amended from time to time by the Board; provided however, that no amendment will be made without the approval of a majority of the Unitholders (i) if so required under the rules and regulations of the New York Stock Exchange or the Securities and Exchange Commission; (ii) that would extend the maximum period during which an award may be granted under the Plan; (iii) materially increase the cost of the Plan to the Partnership; or (iv) result in this Plan no longer satisfying the requirements of Rule 16b-3 of Section 16 of the Exchange Act. The Plan terminates no later that the 10th anniversary of its original effective date.

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Compensation of Directors

We currently pay no additional remuneration to our employees who also serve as directors of the General Partner. Prior to February 2004, our General Partner paid each of its non-employee and nonaffiliated director $10,000 annually, plus $1,000 per board meeting attended and $500 per committee meeting attended. In addition, each of the members of the Independent Committee received a payment of $30,000 during fiscal year 2005, as payment for services and expenses rendered in conjunction with our evaluation of potential acquisition candidates. We will reimburse all expenses associated with the compensation of directors to our General Partner.

Eligible directors receive an annual retainer of $20,000, plus $2,000 per board meeting attended, an additional annual payment of $5,000 to $7,500 for serving on designated committees, plus $1,000 per committee meeting attended, plus an Annual Director s Grant as defined by the 2004 Unit Plan.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table sets forth certain information as of October 31, 2005, regarding the beneficial ownership of our securities by certain beneficial owners, all directors and named executive officers of the general partner of our General Partner, each of the named executive officers and all directors and executive officers of the general partner of our General Partner as a group, of our Common Units, Class C Units and Class E Units. The General Partner knows of no other person not disclosed herein who beneficially owns more than 5% of our Common Units.

Energy Transfer Partners, L.P. Units

Title of Class	Name and Address of Beneficial Owner (1)	Beneficially Owned (2)	Percent of Class
Common Units	Ray C. Davis (3)	1,000	*
	Kelcy L. Warren (3)		*
	H. Michael Krimbill (4) (6)	722,118	*
	Bill W. Byrne	158,544	*
	J. Charles Sawyer	139,544	*
	Stephen L. Cropper (4)	17,230	*
	David R. Albin (5)		*
	Kenneth A. Hersh (5)		*
	Paul E. Glaske	41,563	*
	K. Rick Turner (5)	4,563	*
	Ted Collins, Jr.	10,563	*
	John McReynolds	4,748	*
	R.C. Mills (4)	691,018	*
	Mackie McCrea (3)		*
	Bradley K. Atkinson (6)	109,200	*
	Robert A. Burk (6)		*
	John Daigh (3)		*
	Karen Z. Hicks (6)	4,510	*
	All Directors and Executive Officers as a group (18 persons)	1,904,101	1.78%

	ETE (7)	32,173,840	30.1%
	FHM Investments, L.L.C. (3) (6)	1,308	*
Class C Units	FHS Investments, L.L.C. (8)	1,000,000	100%
Class E Units	Heritage Holdings, Inc. (9)	8,853,832	100%

* Less than one percent (1%)

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(1) The address for Messrs. Davis and Warren is 2838 Woodside Street, Dallas, Texas 75204. The address for Heritage Holdings and Messrs. Krimbill, Atkinson, Burk and Daigh is 8801 S. Yale Avenue, Suite 310, Tulsa, Oklahoma 74137. The address for Messrs. Albin and Hersh is 125 E. John Carpenter Freeway, Suit 600, Irving, Texas 75062. The address for Mr. McCrea is 800 E. Sonterra Blvd., San Antonio, Texas 78258. The address for Mr. Mills is 5000 Sawgrass Village, Suite 4, Ponte Vedra Beach, Florida 32082. The address for ETE and Mr. McReynolds is 2828 Woodside Street, Dallas, Texas 75204. The address for Ms. Hicks is 2225 11th Ave., Helena, Montana, 59601. The address for FHS Investments is 2215 B Renaissance Dr., Suite 5, Las Vegas, Nevada 89119. The address for FHM Investments is 7005 Quail Rock Lane, Reno, Nevada 89511. The address for Messrs. Byrne, Cropper, Collins, Glaske, Sawyer, and Turner is 2838 Woodside Street, Dallas, Texas 75204.

(2) Beneficial ownership for the purposes of the foregoing table is defined by Rule 13-d-3 under the Securities Exchange Act of 1934. Under that rule, a person is generally considered to be the beneficial owner of a security if he has or shares the power to vote or direct the voting thereof (Voting Power) or to dispose or direct the disposition thereof (Investment Power) or has the right to acquire either of those powers within sixty (60) days.

(3) Due to the ownership of Messrs. Davis, Daigh, Warren, McCrea, and FHM Investments in ETE, they may be deemed to beneficially own the limited partnership interests held by ETE, to the extent of their respective interests therein. Any such deemed ownership is not reflected in the table.

(4) Each of Messrs. Mills, Cropper and Krimbill shares Voting and Investment Power on a portion of their respective units with his/her spouse.

(5) Each of Messrs. Albin, Hersh, and Turner are representatives of or owners in entities owning interests in ETE and may be deemed to beneficially own the limited partnership interest held by ETE though such ownership is not depicted in the table.

(6) FHM Investments is owned by a group of our executive managers, including officers of our General Partner. Due to the ownership of Messrs. Atkinson, Burk and Krimbill and Ms. Hicks in FHM Investments, they may be deemed to beneficially own the limited partner interests held by FHM Investments to the extent of their respective interests therein and the limited partner interests held by ETE to the extent of FHM Investments respective interests therein. Any such deemed ownership is not reflected in the table. Mr. Krimbill is the sole managing member of FHM Investments.

(7) ETE owns all of the member interests of Energy Transfer Partners, L.L.C. and all of the limited partner interests in Energy Transfer Partners GP, L.P. Energy Transfer Partners, L.L.C. is the general partner of Energy Transfer Partners, GP, L.P. with a .01% general partner interest. LE GP, LLC, the general partner of ETE may be deemed to beneficially own the Common Units owned of record by ETE. The sole members of LEGP, L.L.C. are Ray C. Davis, Kelcy L. Warren and Natural Gas Partners VI, L.P. (the NGP Fund). G.F.W. Energy VI L.P. is the sole general partner of the NGP Fund and G.F.W. VI, L.L.C. is the sole general partner of G.F.W. Energy VI L.P. Messrs. Hersh and Albin, who constitute a majority of the members of G.F.W. VI, L.L.C., may also be deemed to share power to vote or to direct the vote and to dispose or to direct the disposition of, the Common Units held by ETE.

(8) FHS Investments, L.L.C. is owned by the former stockholders of Heritage Holdings. Based on their ownership interest in FHS Investments, each of Messrs. Krimbill, Mills, Sawyer, and Byrne may be deemed to own the limited partner interests held by FHS investments to the extent of their respective interests therein. Messrs. Krimbill and Mills serve as managers of FHS Investments.

(9) Energy Transfer Partners, L.P. indirectly owns 100% of the common stock of Heritage Holdings, Inc.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Our natural gas midstream operations secure compression services from third parties. Energy Transfer Technologies, Ltd. is one of the entities from which compression services are obtained. Energy Transfer Group, LLC is the general partner of Energy Transfer Technologies, Ltd. These entities are collectively referred to as the ETG Entities . The ETG Entities were not acquired by us in conjunction with the January 2004 Energy Transfer Transactions. Our Co-Chief Executive Officers, Ray C. Davis and Kelcy L. Warren have an indirect ownership interest in and one of our directors Ted Collins, Jr., has an ownership interest in the ETG Entities. In addition, two of our directors, Ted Collins, Jr. and John W. McReynolds, serve on the Board of Directors of the ETG Entities. The terms of each arrangement to provide compression services are negotiated at an arms-length basis by management and are reviewed and approved by the Audit Committee. During fiscal years August 31, 2005 and 2004, payments totaling $900,000 and $279,000, respectively, were made to the ETG Entities for compression services provided to and utilized in our natural gas midstream operations.

Under the terms of a Shared Services Agreement entered into in connection with the Energy Transfer Transactions, the ETG Entities lease office space and obtain related services from us. Payments totaling $0.2 million were paid by the ETG Entities during the fiscal year ended August 31, 2005.

In connection with the HPL acquisition, ETC OLP entered into a short-term loan agreement with Energy Transfer Equity, L.P. (formerly La Grange Energy, L.P.) (ETE), whereby ETC OLP borrowed $174.6 million to acquire the working inventory of natural gas stored in the Bammel storage facilities with interest based on the Eurodollar Rate plus 3.0% per annum. ETC OLP also incurred $3.1 million in debt issuance costs associated with the loan agreement. The loan was paid in full during the year ended August 31, 2005. ETE is the owner of our General Partner. Our Co-Chief Executive Officers serve as Co-Chairmen of the Board of Directors, and one of our directors, John W. McReynolds, serves as the President, Chief Financial Officer and Director of ETE s general partner, LE GP, LLC. In addition, Messrs. Davis, Warren, Krimbill, Albin, Hersh, Turner, McReynolds, McCrea, Daigh, Burk, and Atkinson, and Ms. Hicks, each an officer and/or director of our General Partner, directly or indirectly own interests in ETE.

At August 31, 2005, our natural gas midstream subsidiaries owned a 50% interest in South Texas Gas Gathering, a joint venture that owns an 80% interest in the Dorado System, a 61-mile gathering system located in South Texas. The other 50% equity interest in South Texas Gas Gathering is owned by an entity that is owned in part by Ted Collins, Jr., one of the General Partner s directors. We are the operator of the Dorado System. At August 31, 2004, there was a balance of $248,000 owing to us by the entity that is owned in part by Mr. Collins for services provided as operator, which was paid in full during the year ended August 31, 2005.

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During the fiscal year ended August 31, 2005, payments of approximately $1.0 million were made to the law firm of Hunton & Williams for legal services rendered. These services were provided to ETC OLP and the Partnership in connection with the Energy Transfer Transactions in January of 2004, the acquisition of the HPL System, and for the representation of ETC OLP in other matters. John W. McReynolds, a director of our General Partner since August 2004, was a partner in the Dallas, Texas office of Hunton & Williams until March 2005.

In June 2005, we completed the sale of 1,640,000 Common Units to a group of our executive managers including the President, Vice-President and General Counsel, and Vice-President-Corporate Development. The units were sold at a price of $31.95 per Common Unit, which represented a 6% discount to the closing Common Unit price on June 17, 2005. The price received was based on the fair market value and we believe is comparable to the price that we would have received from an unaffiliated purchaser in a large block equity transaction. The transaction was approved by both the special committee of independent directors and the audit committee of the General Partner.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The following set forth fees billed by Grant Thornton LLP for the audit of our annual financial statements and other services rendered for the fiscal years ended August 31, 2005 and 2004:

	Year Ended August 31,	
	2005	2004
Audit fees (1)	$ 3,489,522	$ 1,024,033
Audit related fees (2)	$ 5,000	$ 1,500
Tax fees (3)	$	$
All other fees (4)	$	$
Total	$ 3,494,522	$ 1,025,533

(1) Includes fees for audits of annual financial statements of our companies, reviews of the related quarterly financial statements, and services that are normally provided by the independent accountants in connection with statutory and regulatory filings or engagements, including reviews of documents filed with the Securities and Exchange Commission and services related to the audit of our internal controls over financial reporting.
(2) Includes fees related to consultations concerning financial accounting and reporting standards and work paper access.
(3) Includes fees related to professional services for tax compliance, tax advice, and tax planning.
(4) Consists of fees for services other than services reported above.

Pursuant to the charter of the Audit Committee, they are responsible for the oversight of our accounting, reporting and financial practices. The Audit Committee has the responsibility to select, appoint, engage, oversee, retain, evaluate and terminate our external auditors; pre-approve all audit and non-audit services to be provided, consistent with all applicable laws, to us by our external auditors; and establish the fees and other compensation to be paid to our external auditors. The Audit Committee also oversees and directs our internal auditing program and reviews our internal controls.

The Audit Committee has adopted a policy for the pre-approval of audit and permitted non-audit services provided by our principal independent accountants. The policy requires that all services provided by Grant Thornton LLP including audit services, audit-related services, tax services

and other services, must be pre-approved by the Committee.

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The Audit Committee reviews the external auditors proposed scope and approach as well as the performance of the external auditors. It also has direct responsibility for and sole authority to resolve any disagreements between our management and our external auditors regarding financial reporting, regularly reviews with the external auditors any problems or difficulties the auditors encountered in the course of their audit work, and, at least annually, uses its reasonable efforts to obtain and review a report from the external auditors addressing the following (among other items):

the auditors internal quality-control procedures;

any material issues raised by the most recent internal quality-control review, or peer review, of the external auditors;

the independence of the external auditors;

the aggregate fees billed by our external auditors for each of the previous two fiscal years; and

the rotation of the lead partner.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES.

(a) 1. Financial Statements.

See Index to Financial Statements set forth on page F-1.

2. Financial Statement Schedules.

None.

3. Exhibits.

See Index to Exhibits set forth on page E-1.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ENERGY TRANSFER PARTNERS, L.P.

By Energy Transfer Partners GP, L.P, its General Partner.

By Energy Transfer Partners, L.L.C., its General Partner

By: /s/ Ray C. Davis

Ray C. Davis
Co-Chief Executive Officer and officer duly

authorized to sign on behalf of the registrant

By: /s/ Kelcy L. Warren

Kelcy L. Warren
Co-Chief Executive Officer and officer duly authorized to sign on behalf of the registrant

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons in the capacities and on the dates indicated:

Signature	Title	Date
/s/ Ray C. Davis Ray C. Davis	Co-Chief Executive Officer and Co-Chairman of the Board (Principal Executive Officer)	November 14, 2005
/s/ Kelcy L. Warren Kelcy L. Warren	Co-Chief Executive Officer and Co-Chairman of the Board (Principal Executive Officer)	November 14, 2005
/s/ H. Michael Krimbill H. Michael Krimbill	President, Chief Financial Officer and Director (Principal Financial and Accounting Officer)	November 14, 2005
/s/ Bill W. Byrne Bill W. Byrne	Director	November 14, 2005

/s/ David R. Albin	Director	November 14, 2005
David R. Albin		
/s/ Kenneth A. Hersh	Director	November 14, 2005
Kenneth A. Hersh		
/s/ Paul E. Glaske	Director	November 14, 2005
Paul E. Glaske		
/s/ K. Rick Turner	Director	November 14, 2005
K. Rick Turner		
/s/ Ted Collins, Jr.	Director	November 14, 2005
Ted Collins, Jr.		
/s/ John W. McReynolds	Director	November 14, 2005
John W. McReynolds		

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INDEX TO FINANCIAL STATEMENTS

Energy Transfer Partners, L.P. and Subsidiaries

(Formerly Energy Transfer Company and surviving legal entity in the Energy Transfer Transactions)

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Consolidated Balance Sheets August 31, 2005 and 2004	F-4
Consolidated Statements of Operations Years Ended August 31, 2005, 2004 and Eleven Months Ended August 31, 2003	F-6
Consolidated Statements of Comprehensive Income (Loss) Years Ended August 31, 2005, 2004, and Eleven Months Ended August 31, 2003	F-7
Consolidated Statements of Partners Capital Years Ended August 31, 2005, 2004, and Eleven Months Ended August 31, 2003	F-8
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PART I FINANCIAL INFORMATION

The consolidated financial statements of Energy Transfer Partners, L.P. (ETP or the Partnership) presented herein for the year ended August 31, 2005 include the results of operations for Energy Transfer Company (ETC) and Heritage Operating, L.P. (referenced herein as Heritage) and Heritage Holdings, Inc. (HHI) for the entire period from September 1, 2004 through August 31, 2005.

The financial statement information presented for the year ended August 31, 2004, and the eleven months ended August 31, 2003, include the results of operations for ETP, which in turn include the results of operations for La Grange Acquisition, L.P. (ETC OLP) for the entire periods from September 1, 2003 to August 31, 2004 and from October 1, 2002 through August 31, 2003. However, the results of operations for Heritage are only included for the period from January 20, 2004 to August 31, 2004. Thus, the results of operations do not represent the entire results of operations for Heritage for the year ended August 31, 2004, as they do not include the results of operations of Heritage for the period prior to the Energy Transfer Transactions on January 20, 2004. Please read notes 1 and 2 to the Energy Transfer Partners, L.P. Consolidated Financial Statements for further explanation regarding the Energy Transfer Transactions. In addition, ETC OLP acquired the TUFCO System from TXU Fuel Company, a subsidiary of TXU Corp on June 2, 2004. The former TUFCO System is referred to as the ET Fuel System. The accompanying financial statements include the results of operations of the ET Fuel System beginning June 2, 2004, the Bossier Pipeline (now known as the East Texas Pipeline) since June 21, 2004, and the Houston Pipeline System beginning January 26, 2005. The comparability of the accompanying consolidated financial statements are also affected by other acquisitions and the disposition of ETC Oklahoma Pipeline, Ltd. (Elk City) as described in Notes 2, 5 and 6.

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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 collectively, the Partnership, as of August 31, 2005 and 2004 and the related consolidated statements of operations, comprehensive income, partners capital, and cash flows for each of the two years in the period ended August 31, 2005 and for the eleven months ended August 31, 2003. 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, 2005 and 2004 and the results of their operations and their cash flows for each of the two years in the period ended August 31, 2005 and for the eleven months ended August 31, 2003 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 the Partnership s internal control over financial reporting as of August 31, 2005, 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 8, 2005 expressed an unqualified opinion thereon.

/s/ Grant Thornton LLP

Tulsa, Oklahoma

November 8, 2005

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ITEM 1. FINANCIAL STATEMENTS

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

(FORMERLY ENERGY TRANSFER COMPANY)

CONSOLIDATED BALANCE SHEETS

(in thousands, except unit data)

	August 31, 2005	August 31, 2004 (see Note 5)
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 24,914	$ 81,745
Marketable securities	3,452	2,464
Accounts receivable, net of allowance for doubtful accounts	847,028	251,346
Accounts receivable from related companies	4,479	34
Inventories	302,893	53,261
Assets held for sale		67,908
Deposits paid to vendors	65,034	3,023
Exchanges receivable	35,623	8,640
Price risk management assets	138,961	4,615
Prepaid expenses and other	35,636	7,399
Total current assets	1,458,020	480,435
PROPERTY, PLANT AND EQUIPMENT, net	2,440,565	1,424,095
LONG-TERM PRICE RISK MANAGEMENT ASSETS	41,687	
INVESTMENT IN AFFILIATES	37,353	8,010
GOODWILL	324,019	313,720
INTANGIBLES AND OTHER ASSETS, net	112,159	100,421
OTHER LONG-TERM ASSETS	13,103	423
Total assets	$ 4,426,906	$ 2,327,104

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

(FORMERLY ENERGY TRANSFER COMPANY)

CONSOLIDATED BALANCE SHEETS

(in thousands, except unit data)

	August 31, 2005	August 31, 2004 (see Note 5)
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES:		
Working capital facility	$ 17,026	$ 14,550
Accounts payable	818,775	235,631
Accounts payable to related companies	1,073	4,276
Exchanges payable	33,772	2,657
Customer deposits	88,038	11,378
Liabilities from discontinued operations		20,590
Accrued and other current liabilities	146,006	73,484
Price risk management liabilities	104,772	1,262
Income taxes payable	2,063	2,252
Current maturities of long-term debt	39,349	30,957
Total current liabilities	1,250,874	397,037
LONG-TERM DEBT, less current maturities	1,675,705	1,070,871
LONG-TERM PRICE RISK MANAGEMENT LIABILITIES	30,517	
LONG-TERM AFFILIATED PAYABLE	2,005	
DEFERRED TAXES	111,185	109,896
OTHER NON-CURRENT LIABILITIES	13,284	845
MINORITY INTERESTS	17,144	1,475
	3,100,714	1,580,124
COMMITMENTS AND CONTINGENCIES		
PARTNERS CAPITAL:		
Common Unitholders (106,889,904 and 89,118,062 units authorized, issued and outstanding at August 31, 2005 and 2004, respectively)	1,362,125	720,187
Class C Unitholders (1,000,000 units authorized, issued and outstanding at August 31, 2005 and 2004)		
Class E Unitholders (8,853,832 authorized, issued and outstanding at August 31, 2005 and 2004, held by subsidiary and reported as treasury units)		
General Partner	49,384	26,761
Accumulated other comprehensive income (loss)	(85,317)	32
Total partners capital	1,326,192	746,980
Total liabilities and partners capital	$ 4,426,906	$ 2,327,104

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

(FORMERLY ENERGY TRANSFER COMPANY)

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per unit and unit data)

	For the Year Ended August 31, 2005	For the Year Ended August 31, 2004	For the Eleven Months Ended August 31, 2003
			(Energy Transfer Company)
		(see Notes 2 and 5)	(see Notes 2 and 5)
REVENUES:			
Midstream and transportation and storage	$ 5,383,625	$ 1,966,803	$ 931,027
Propane	709,904	342,523	
Other	75,269	37,631	
Total revenues	6,168,798	2,346,957	931,027
COSTS AND EXPENSES:			
Cost of products sold	5,381,515	1,981,424	825,438
Operating expenses	319,554	147,374	25,046
Depreciation and amortization	92,943	48,599	11,870
Selling, general and administrative	62,735	30,471	13,078
Total costs and expenses	5,856,747	2,207,868	875,432
OPERATING INCOME	312,051	139,089	55,595
OTHER INCOME (EXPENSE):			
Interest expense	(93,017)	(41,190)	(12,456)
Loss on extinguishment of debt	(9,550)		
Equity in earnings (losses) of affiliates	(376)	363	1,423
Loss on disposal of assets	(330)	(1,006)	
Other, net	631	509	501
INCOME FROM CONTINUING OPERATIONS BEFORE MINORITY INTERESTS AND INCOME TAX EXPENSE	209,409	97,765	45,063
Minority interests	(731)	(295)	
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE	208,678	97,470	45,063
Income tax expense	(7,295)	(4,481)	(4,432)
INCOME FROM CONTINUING OPERATIONS	201,383	92,989	40,631

DISCONTINUED OPERATIONS:			
Income from discontinued operations	5,498	6,163	5,994
Gain on sale of discontinued operations, net of income tax expense	142,469		
Total income from discontinued operations	147,967	6,163	5,994
NET INCOME	349,350	99,152	46,625
GENERAL PARTNER S INTEREST IN NET INCOME	45,442	8,938	932
LIMITED PARTNERS INTEREST IN NET INCOME	$ 303,908	$ 90,214	$ 45,693
BASIC NET INCOME PER LIMITED PARTNER UNIT			
Limited Partners income from continuing operations	$ 1.79	$ 1.62	$ 3.01
Limited Partners income from discontinued operations	0.81	0.11	0.44
NET INCOME PER LIMITED PARTNER UNIT	$ 2.60	$ 1.73	$ 3.45
BASIC AVERAGE NUMBER OF UNITS OUTSTANDING	97,646,351	52,228,742	13,243,474
DILUTED NET INCOME PER LIMITED PARTNER UNIT			
Limited Partners income from continuing operations	$ 1.79	$ 1.62	$ 3.01
Limited Partners income from discontinued operations	0.81	0.11	0.44
NET INCOME PER LIMITED PARTNER UNIT	$ 2.60	$ 1.73	$ 3.45
DILUTED AVERAGE NUMBER OF UNITS OUTSTANDING	97,900,277	52,283,210	13,243,474

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

(FORMERLY ENERGY TRANSFER COMPANY)

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(in thousands)

	For the Year Ended August 31, 2005	For the Year Ended August 31, 2004 (see Note 2)	For the Eleven Months Ended August 31, 2003 (Energy Transfer Company)
NET INCOME	$ 349,350	$ 99,152	$ 46,625
OTHER COMPREHENSIVE INCOME:			
Reclassification adjustment for gains (losses) on derivative instruments included in net income accounted for as hedges	25,280	(3,396)	
Change in value of derivative instruments accounted for as hedges	(111,617)	3,481	
Change in value of available-for-sale securities	988	(53)	
Comprehensive income	$ 264,001	$ 99,184	$ 46,625
Reconciliation of Accumulated Other Comprehensive Income (Loss)			
Balance, beginning of period	$ 32	$	$
Current period reclassification to earnings	25,280	(3,396)	
Current period change	(110,629)	3,428	
Balance, end of period	$ (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

(FORMERLY ENERGY TRANSFER COMPANY)

CONSOLIDATED STATEMENTS OF PARTNERS CAPITAL

(in thousands, except unit data)

	Number of Units												
	Common	Class C	Class D	Class E	Special	Common	Class C	Class D	Class E	Special	General Partner	Accumulated Other Comprehensive Income (Loss)	Total
Balance, October 1, 2002						$	$	$	$	$	$	$	$
Capital contribution	13,243,474					139,180					108		139,288
Distribution to parent						(4,815)					(10)		(4,825)
Net income						46,531					94		46,625
Balance, August 31, 2003	13,243,474					180,896					192		181,088
Distribution to parent						(208,927)							(208,927)
Unit distribution						(52,963)		(5,405)			(5,015)		(63,383)
Merger with Heritage	33,005,826	1,000,000	15,443,084		7,485,030	103,631		205,382		38,000	(896)		346,117
Conversion of Class E Units	(8,853,832)			8,853,832		(158,235)			158,235				
Class E Units held by subsidiary and reported as treasury units				(8,853,832)					(158,235)				(158,235)
Issuance of Common Units	28,750,000					528,129							528,129
General Partner capital contribution						(1,027)		(284)			23,542		22,231
Issuance of Common Units in connection with certain acquisitions	44,480					734							734
Conversion of Class D and Special Units	22,928,114		(15,443,084)		(7,485,030)	256,007		(218,007)		(38,000)			
Net change in accumulated												32	32

other comprehensive income per accompanying statements													
Other						42							42
Net income						71,900		18,314			8,938		99,152
Balance, August 31, 2004	89,118,062	1,000,000				$ 720,187	$	$	$	$	$ 26,761	$ 32	$ 746,980

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

(FORMERLY ENERGY TRANSFER COMPANY)

CONSOLIDATED STATEMENTS OF PARTNERS CAPITAL

(in thousands, except unit data)

	Number of Units												
	Common	Class C	Class D	Class E	Special	Common	Class C	Class D	Class E	Special	General Partner	Accumulated Other Comprehensive Income (Loss)	Total
Balance forward August 31, 2004	89,118,062	1,000,000				$ 720,187	$	$	$	$	$ 26,761	$ 32	$ 746,980
Unit distribution						(173,802)					(33,237)		(207,039)
General Partner capital contribution											10,418		10,418
Issuance of Common Units in connection with certain acquisitions	120,550					2,500							2,500
Issuance of Common Units	17,602,960					507,724							507,724
Issuance of restricted Common Units	48,332												
Net change in accumulated other comprehensive income per accompanying statement												(85,349)	(85,349)
Deferred compensation on restricted units and long term incentive plan						1,608							1,608
Net income						303,908					45,442		349,350
Balance, August 31, 2005	106,889,904	1,000,000				$ 1,362,125	$	$	$	$	$ 49,384	$ (85,317)	$ 1,326,192

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

(FORMERLY ENERGY TRANSFER COMPANY)

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Year Ended August 31, 2005	Year Ended August 31, 2004 (see Note 2 and Note 5)	Eleven Months Ended August 31, 2003 (see Note 2 and Note 5)
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 349,350	$ 99,152	$ 46,625
Reconciliation of net income to net cash provided by operating activities:			
Depreciation and amortization related to continuing and discontinued operations	94,490	50,848	13,461
Amortization of deferred finance costs charged to interest	4,049	2,642	2,464
Write off of deferred financing fees	9,522		
Provision for loss on accounts receivable	5,523	1,667	
Loss on disposal of assets	330	1,006	
Gain on sale of discontinued operations before income tax expense	(146,401)		
Deferred compensation on restricted units and long-term incentive plan	1,608	42	
Undistributed losses (earnings) of affiliates	376	(363)	(1,423)
Deferred income taxes	1,289	(3,723)	(1,116)
Minority interests	540	502	104
Other, net	(6)		90
Changes in assets and liabilities, net of effect of acquisitions:			
Accounts receivable	(242,885)	(101,976)	(85,320)
Accounts receivable from related companies	(4,445)	331	
Inventories	(116,889)	35,457	(1,106)
Deposits paid to vendors	(62,011)	16,030	(19,053)
Exchanges receivable	(18,412)	(7,479)	(640)
Prepaid expenses and other	(4,650)	2,449	
Intangibles and other assets	(433)	(1,499)	2,046
Other long-term assets	(1,834)		
Accounts payable	297,968	58,278	97,270
Accounts payable to related companies	(5,194)	599	(2,539)
Exchanges payable	9,320	1,436	1,410
Deposits from customers	76,657	(222)	11,600
Accrued and other current liabilities	50,942	10,308	4,592
Other long-term liabilities	(834)	688	53
Income taxes payable	(189)	(315)	1,793
Price risk management liabilities, net	(128,363)	(3,163)	(105)
Net cash provided by operating activities	169,418	162,695	70,206
CASH FLOWS FROM INVESTING ACTIVITIES:			

Cash paid for acquisitions, net of cash acquired	(1,131,844)	(681,835)	(340,187)
Capital expenditures	(196,459)	(109,688)	(11,914)
Proceeds from the sale of discontinued operations	191,606		
Cash invested in affiliates	(2,355)	(322)	
Dividend from affiliate			1,000
Proceeds from the sale of assets	5,303	1,108	9,843
Net cash used in investing activities	(1,133,749)	(790,737)	(341,258)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from borrowings	2,954,034	894,079	246,000
Principal payments on debt	(2,337,931)	(510,084)	(20,000)
Proceeds from borrowings from related companies	174,624		
Payments on borrowings from related companies	(174,624)		
Net proceeds from issuance of Common Units	507,724	528,129	
Capital contribution from General Partner	10,418	22,231	108,723
Distributions to parent		(206,071)	(4,825)
Debt issuance costs	(19,706)	(8,236)	(5,724)
Unit distributions	(207,039)	(63,383)	
Net cash provided by financing activities	907,500	656,665	324,174
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(56,831)	28,623	53,122
CASH AND CASH EQUIVALENTS, beginning of period	81,745	53,122	
CASH AND CASH EQUIVALENTS, end of period	$ 24,914	$ 81,745	$ 53,122

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

(FORMERLY ENERGY TRANSFER COMPANY)

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Year Ended August 31, 2005	Year Ended August 31, 2004 (see Note 2 and Note 5)	Eleven Months Ended August 31, 2003 (see Note 2 and Note 5)
NONCASH INVESTING ACTIVITIES:			
Assets contributed to subsidiaries	$	$	$ (31,017)
NONCASH FINANCING ACTIVITIES:			
Notes payable incurred on noncompete agreements	$ 2,148	$ 215	$
Issuance of Common Units in connection with certain acquistions	$ 2,500	$ 734	$
General Partner capital contribution	$	$ 1,311	$
Contributed assets	$	$ 1,743	$
Distributions payable to parent	$	$ 2,856	$
Assets and subsidiary interests contributed by partners	$	$	$ 31,017
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:			
Cash paid during the period for interest, net of $191, $926 and $0 capitalized for August 31, 2005, 2004 and 2003, respectively	$ 87,589	$ 37,944	$ 8,846
Cash paid during the period for income taxes	$ 7,538	$ 7,227	$ 2,935

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

(FORMBERLY ENERGY TRANSFER COMPANY)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

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, 2005 and August 31, 2004 and the eleven months ended August 31, 2003 include the results of operations for Energy Transfer Partners, L.P. (ETP), which in turn include the results of operations for La Grange Acquisition, L.P. (ETC OLP) for the entire periods presented. However, the results of operations for Heritage Propane Partners, L.P. (Heritage) and Heritage Holdings, Inc. (HHI), are only included subsequent to January 20, 2004. Thus, the results of operations do not represent the entire results of operations for Heritage and HHI for the year ended August 31, 2004, as they do not include the results of operations of Heritage and HHI for the period prior to the Energy Transfer Transactions on January 20, 2004. The Energy Transfer Transactions are described in Note 1 below. On June 2, 2004, ETC OLP acquired the TUFCO System from TXU Fuel Company, a subsidiary of TXU Corp. The former TUFCO System is referred to as the ET Fuel System. The accompanying financial statements include the results of operations of the ET Fuel System beginning June 2, 2004, the Bossier Pipeline (now known as the East Texas Pipeline) since June 21, 2004, and the Houston Pipeline System beginning January 26, 2005. The comparability of the accompanying consolidated financial statements are also affected by other acquisitions and the disposition of ETC Oklahoma Pipeline, Ltd. (Elk City) as described in Notes 2, 5 and 6.

1. OPERATIONS AND ORGANIZATION:

The accompanying audited consolidated financial statements and notes thereto of the Partnership 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.

On January 26, 2005, the Partnership completed its acquisition of the Houston Pipeline System and related storage facilities (HPL). For additional information regarding this acquisition and other acquisitions, see Note 6.

Certain prior period amounts have been reclassified to conform with the 2005 presentation. These reclassifications have no impact on net income or total partners capital.

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 its subsidiary, La Grange Acquisition, L.P. and its subsidiaries who conduct business under the assumed name of Energy Transfer Company, (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.

Accounting Treatment of the Energy Transfer Transactions

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 the historical financial statements of the registrant. Consequently, the registrant s financial statements do not reflect 100% of the results of Heritage as those results prior to January 19,

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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 ETC through its acquisition of the General Partner and limited partner interests of Heritage of approximately 35.4%. 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 ETC 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.

ETC received Special Units in the Energy Transfer Transaction 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 has made the final modifications to the purchase price. The table above reflects the final adjustments made to the allocation of the purchase price during the first quarter of fiscal year 2005.

Business Operations

In order to simplify the obligations of Energy Transfer Partners under the laws of several jurisdictions in which it conducts business, the Partnership s activities are conducted only through two subsidiary operating partnerships, ETC OLP, a Texas limited partnership which is engaged in midstream and transportation natural gas operations, and Heritage Operating, L.P. (HOLP) a Delaware limited partnership which is engaged in retail and wholesale propane operations, (collectively the Operating Partnerships). The Partnership, the Operating Partnerships, and the Partnership s and Operating Partnership s other subsidiaries are collectively referred to in this report as Energy Transfer.

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ETC OLP owns and operates through its wholly-owned and majority-owned subsidiaries, natural gas gathering, 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 in Oklahoma. ETC OLP is a Texas limited partnership formed in October 2002 and was 99.9% owned by the Partnership prior to the Energy Transfer Transactions and is 99.9% owned by ETP subsequent to the Energy Transfer Transactions and 0.1% owned 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, 2005, ETC OLP owns an interest in and operates approximately 11,700 miles of natural gas gathering and transportation pipelines, 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. The midstream segment focuses on the transportation, gathering, compression, treating, 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. The transportation and storage segment focuses on the transportation of natural gas through the Oasis Pipeline, the East Texas 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 recently acquired HPL System. As a result of the HPL acquisition, the Partnership has redefined its reportable operating segments as discussed in Note 16.

On May 25, 2005 the Fort Worth Basin Pipeline became commercially operational, at nearly full capacity. The 55-mile, 24 inch natural gas pipeline connects to the Partnership s existing pipelines in North Texas and provides transportation for natural gas production from the Barnett Shale producing area. The construction costs were financed entirely with cash from operations. Subsequent to August 31, 2005, the Partnership announced that the Board of Directors of its General Partner approved two new pipeline construction projects. One project involves the construction of a new pipeline which will loop the first 24 miles of Partnership s existing 55 mile, 24 inch pipeline in the Fort Worth Basin production area and adding up to 12,000 horsepower of incremental compression. The other project involves the expansion of the Partnership s previously announced 264-mile intrastate pipeline project by increasing the pipeline s size from 36 inches to 42 inches and the construction of 24 miles of 30 inch diameter pipe. The aggregated costs of these projects are estimated to be $566,000 and are expected to be funded by a combination of cash from operations and proceeds from existing and future debt and equity transactions. However, there is no assurance that management will be successful in raising additional debt or equity offerings to fund these projects.

HOLP sells propane and propane-related products to more than 700,000 active residential, commercial, industrial, and agricultural customers in 34 states. HOLP is also a wholesale propane supplier in the United States and in Canada, the latter through its participation in MP Energy Partnership. MP Energy Partnership is a Canadian partnership, in which the Partnership owns 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).

Recently Issued Accounting Standards

FASB Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations (FIN 47). In March 2005, the Financial Accounting Standards Board (FASB) published FIN 47, which requires companies to record a liability for those asset retirement obligations in which the timing or amount of settlement of the obligation are uncertain. These conditional obligations were not addressed by SFAS 143. FIN 47 will require the Partnership to accrue a liability when a range of scenarios can be determined. Management intends to adopt FIN 47 no later than the end of the fiscal year ending August 31, 2006, and has not yet determined the impact, if any, that this pronouncement will have on the Partnership s financial statements.

SFAS No. 123 (Revised 2004) (SFAS 123R), Share-Based Payment. In December 2004, the FASB issued SFAS 123R, which replaces SFAS 123 and supercedes Accounting Principles Board (APB) Opinion No. 25. SFAS 123R requires an entity to recognize the grant-date fair-value of

stock options and other equity-based compensation issued to employees in the income statement. The revised statement requires that an entity account for those transactions using the fair-value-based method, and eliminates the intrinsic value method of accounting in APB 25, *Accounting for Stock Issued to Employees*, which was permitted under SFAS 123, as originally issued. The

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revised statement also requires entities to disclose information about the nature of the share-based payment transactions and the effects of those transactions on the financial statements. SFAS 123R is effective for public companies, that are not small business issuers, beginning with their next fiscal year. All public companies must use either the modified prospective or modified retrospective transition method. On March 29, 2005, the SEC staff issued SAB No. 107, (SAB 107) Share-Based Payment, to express the views of the staff regarding the interaction between SFAS 123R and certain SEC rules and regulations and to provide the staff s views regarding the valuation of share-based payment arrangements for public companies. The Partnership has considered the additional guidance provided by SAB 107 in connection with its implementation of SFAS 123R as of September 1, 2005, which did not have a material impact on its consolidated results of operations, cash flows or financial position.

SFAS No. 153 (SFAS 153), Exchanges of Nonmonetary Assets-an amendment of APB Opinion No. 29. In December 2004, the FASB issued SFAS 153, which amends APB Opinion No. 29 by eliminating the exception to the fair-value principle for exchanges of similar productive assets, which were accounted for under APB Opinion No. 29 based on the book value of the asset surrendered with no gain or loss recognition. SFAS 153 also eliminates APB 29 s concept of culmination of an earnings process. SFAS 153 is effective for nonmonetary transactions occurring in fiscal periods beginning after June 15, 2005. The Partnership adopted SFAS 153 during the fiscal quarter ending August 31, 2005 without a material impact on the Partnership s consolidated results of operations, cash flows or financial position.

SFAS No. 154 (SFAS 154), Accounting Changes and Error Correction a replacement of APB Opinion No. 20 and FASB Statement No. 3. 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. 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 the Partnership s consolidated results of operations, cash flows or financial position.

SFAS No. 151 (SFAS 151), Inventory Costs an amendment of ARB No. 43, Chapter 4. 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. The Partnership does not allocate overhead costs to inventory and management has determined that there are no other material items which require the application of SFAS 151.

EITF Issue No. 03-13 (EITF 03-13), Applying the Conditions in Paragraph 42 of SFAS 144, Accounting for the Impairment or Disposal of Long-Lived Assets, in Determining Whether to Report Discontinued Operations. In November 2004, the EITF reached a consensus with respect to evaluating whether the criteria in SFAS 144 has been met for classifying as a discontinued operation a component of an entity that either has been disposed of or is classified as held for sale. To qualify as a discontinued operation, SFAS 144 requires that the cash flows of the disposed component be eliminated from the operations of the ongoing entity and that the ongoing entity not have any significant continuing involvement in the operations of the disposed component after the disposal transaction. The consensus is to be applied prospectively to a component of an entity that is either disposed or classified held for sale in fiscal periods beginning after December 15, 2004. The Partnership accounted for the sale of its discontinued operations in accordance with SFAS 144 and EITF 03-13.

EITF Issue No. 03-6 (EITF 03-6). Participating Securities and the Two-Class method under FASB Statement No. 128. EITF 03-6 requires the calculation of net earnings per limited partner unit for each period presented according to distributions declared and participation rights in undistributed earnings, as if all of the earnings for the period had been distributed. In periods with undistributed earnings above certain levels, the calculation according to the two-class method results in an increased allocation of undistributed earnings to the general partner of ETP and a dilution of the earnings to the limited partners. In periods that may have year-to-date net losses the allocation of the net losses to the limited

partners and the general partner of ETP will be determined based on the same allocation basis specified in the ETP Partnership Agreement that would apply to periods in which there were no undistributed earnings. ETP follows the requirements of EITF 03-6 in calculating their net earnings per limited partner unit.

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EITF Issue No.04-1 (EITF 04-1). Accounting for Preexisting Relationships between the Parties to a Business Combination. EITF 04-1 requires that pre-existing contractual relationships between two parties involved in a business combination be evaluated to determine if a settlement of the pre-existing contracts is required separately from the accounting for the business combination. This consensus is effective for business combinations consummated and goodwill impairment tests performed in reporting periods beginning after October 13, 2004. The Partnership adopted EITF 04-1 during the quarter ended February 28, 2005, without a material effect on its financial position, results of operations and cash flows.

2. PRESENTATION OF FINANCIAL INFORMATION:

The accompanying consolidated financial statements for the year ended August 31, 2005 include the results of operations for ETC OLP, consolidated with the results of operations of HOLP and HHI. In addition, the Partnership acquired the ET Fuel System from TXU Fuel Company, a subsidiary of TXU Corp. on June 2, 2004, and the controlling interests in HPL on January 26, 2005. The results of operations for the ET Fuel System and HPL are included in the consolidated statement of operations since their respective acquisition dates. However, the accompanying financial statements for the year ended August 31, 2004 include the results of operations for ETC OLP for the entire period, consolidated with the results of operations of HOLP and HHI beginning January 20, 2004.

A minority interest liability and minority interest expense are recorded for all partially owned consolidated subsidiaries. All significant intercompany transactions and accounts have been eliminated in consolidation. 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, the Partnership applies proportionate consolidation for its interests in these accounts.

During the eleven months ended August 31, 2003, ETC OLP owned the Southeast Texas System, the Oasis Pipeline, and the Elk City System. From October 1, 2002 through December 27, 2002, ETC OLP also owned a 50% equity interest in Oasis Pipe Line Company, which owns the Oasis Pipeline. After December 27, 2002, ETC OLP owned a 100% interest in Oasis Pipe Line Company when it purchased the remaining 50% from Dow Hydrocarbons and Resources, Inc. In addition, on December 27, 2002, an affiliate of La Grange Energy s general partner contributed to ETC OLP its marketing business (ET Company I) and its interest in the Vantex System, the Rusk County Gathering System, the Whiskey Bay System and the Chalkley Transmission System.

As stated previously, the financial statements of ETC OLP are the financial statements of the registrant, as ETC OLP was deemed the accounting acquirer from the Energy Transfer Transactions. ETC OLP was formed on October 1, 2002, and has an August 31 year-end.

The following unaudited pro forma consolidated results of operations for the year ended August 31, 2005 are presented as if the HPL acquisition had been made on September 1, 2004 and includes income from discontinued operations and the gain on the sale of discontinued operations. The pro-forma consolidated results of operations for the year ended August 31, 2004, are presented as if the ET Fuel System acquisition, the HPL acquisition and the Energy Transfer Transactions had been made on September 1, 2003. The pro forma consolidated net income and earnings per unit include the income from discontinued operations as presented on the consolidated income statements for the years ended August 31, 2005 and 2004, and the eleven months ended August 31, 2003.

	Year Ended	Year Ended	Eleven Months Ended

	August 31, 2005	August 31, 2004	August 31, 2003
Revenues	$ 7,837,022	$ 6,316,534	$ 1,683,654
Net income	$ 376,400	$ 125,897	$ 92,925
Basic earnings per Limited Partner Unit	$ 2.61	$ 1.33	$ 1.31
Diluted earnings per Limited Partner Unit	$ 2.61	$ 1.33	$ 1.30

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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 effects of the Texas Chalk and Madison Systems acquired in November 2004 or 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. In addition, the acquisition of ten propane businesses that were acquired during the year ended August 31, 2005 and the propane acquisitions that were completed during the year ended August 31, 2004, are not included in the pro forma consolidated results of operations above. 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.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND BALANCE SHEET DETAIL:

Cash and Cash Equivalents

Cash and cash equivalents include all cash on hand, demand deposits, and investments with original maturities of three months or less. The Partnership considers 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.

Marketable Securities

Marketable securities owned by the Partnership are classified as available-for-sale securities and are reflected as a current asset on the consolidated balance sheet at their fair value. The Partnership reported unrealized holding gains of $988 for the year ended August 31, 2005, and unrealized holding losses of $53 for the year ended August 31, 2004, and $0 for the eleven months ended August 31, 2003 on its marketable securities.

Accounts Receivable

The Partnership s 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 each week. 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 the Partnership s accounts receivable of the midstream and transportation and storage segments was not significant at the end of the 2005 and 2004 fiscal years; therefore, an allowance for doubtful accounts for the midstream and transportation and storage segments was not deemed necessary at August 31, 2005 or 2004. Bad debt expense related to these receivables is recognized at the time an account is deemed uncollectible. There was no bad debt expense recorded during the year ended August 31, 2005, and $123 was recorded for the year ended August 31, 2004 in the midstream and transportation and storage segments, respectively. There was no bad debt expense recorded for the eleven months ended August 31, 2003 in the midstream and transportation and storage segments.

The Partnership enters 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 grants credit to its customers for the purchase of propane and propane-related products. Also included in accounts receivable are trade accounts receivable arising from HOLP s retail and wholesale propane operations and receivables arising from liquids marketing activities. Accounts receivable for retail and wholesale propane segments are recorded as amounts 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. Management s assessment is based on the overall creditworthiness of the Partnership s customers and any specific disputes. The accounts receivable for HOLP were marked to fair market value in connection with the Energy Transfer Transactions. Accounts receivable consisted of the following excluding amounts related to discontinued operations:

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	August 31, 2005	August 31, 2004
Accounts receivable - midstream and transportation and storage	$ 782,090	$ 206,023
Accounts receivable - propane	69,014	46,990
Less allowance for doubtful accounts	(4,076)	(1,667)
Total, net	$ 847,028	$ 251,346

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

	Year Ended August 31, 2005	Year Ended August 31, 2004	Eleven Months Ended August 31, 2003
Balance, beginning of the period	$ 1,667	$	$
Provision for loss on accounts receivable	5,523	1,667	
Accounts receivable written off, net of recoveries	(3,114)		
Balance, end of period	$ 4,076	$ 1,667	$

Inventories

ETC OLP s inventories consist principally of natural gas held in storage, which is valued at the lower of cost or market utilizing the weighted-average cost method. Propane inventories are also valued at the lower of cost or market. The cost of propane inventories is determined using weighted-average cost of propane delivered to the customer service locations, and includes storage fees and inbound freight costs, while the cost of appliances, parts, and fittings is determined by the first-in, first-out method. Inventories consisted of the following, excluding amounts related to discontinued operations:

	August 31, 2005	August 31, 2004
Natural gas, propane and other NGLs	$ 288,657	$ 40,926
Appliances, parts and fittings and other	14,236	12,335
Total inventories	$ 302,893	$ 53,261

Deposits

The Partnership uses a combination of financial instruments including, but not limited to, futures, price swaps and basis trades to manage its exposure to market fluctuations in the prices of natural gas and NGLs. The Partnership enters into these financial instruments with brokers who are clearing members with the New York Mercantile Exchange (the NYMEX) and directly with counterparties in the over-the-counter (OTC) market and is subject to margin deposit requirements under the OTC agreements and NYMEX positions. The 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 of one of the counterparties when the financial instrument settles. The Partnership also has maintenance margin deposits with certain counterparties in the OTC market. The payments on margin deposits occur when the value of a derivative(s) exceed(s) the Partnership s pre-established credit limit with the counterparty. Margin deposits are returned to the Partnership on the settlement date. The Partnership had net deposits with derivative counterparties of $65,034 and $23 as of August 31, 2005 and 2004, respectively. Deposits are also paid to vendors in ETC OLP s business as prepayments for natural gas deliveries in the following month. The Partnership also makes prepayments when the volume of business with a vendor exceeds the Partnership s credit limit and/or when it is economically beneficial to do so. There were no deposits with vendors for gas purchases as of August 31, 2005 and $3,000 of deposits for gas purchases as of August 31, 2004, respectively.

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Deposits are received from ETC OLP s customers as prepayments for natural gas deliveries in the following month and deposits from propane customers as security 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. Deposits received from customers were $88,038 and $11,378 as of August 31, 2005 and 2004, respectively.

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 the Partnership s 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, the Partnership capitalizes 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 operations.

The Partnership reviews long-lived assets for impairment 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, the Partnership reduces the carrying amount of such assets to fair value. No impairment of long-lived assets was recorded during the periods presented.

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

	August 31,	
	2005	2004
Land and improvements	$ 39,551	$ 27,771
Buildings and improvements (10 to 30 years)	46,829	34,574
Pipelines and equipment (10 to 65 years)	1,574,519	788,025
Natural gas storage (40 years)	40,817	24,277
Bulk storage, equipment and facilities (3 to 30 years)	58,825	48,947
Tanks and other equipment (5 to 30 years)	346,924	328,026
Vehicles (5 to 10 years)	81,998	56,740
Right of way (20 to 65 years)	90,683	58,389
Furniture and fixtures (3 to 10 years)	11,995	7,324
Linepack	25,100	12,802

Pad Gas	102,557	42,136
Other (5 to 10 years)	17,893	5,581
	2,437,691	1,434,592
Less Accumulated depreciation	(136,804)	(53,408)
	2,300,887	1,381,184
Plus Construction work-in-process	139,678	42,911
Property, plant and equipment, net	$ 2,440,565	$ 1,424,095

Capitalized interest is included for pipeline construction projects. Interest is capitalized based on the current borrowing rate. A total of $191 and $926 of interest has been capitalized for pipeline construction projects for the years ended August 31, 2005 and 2004, respectively.

Asset Retirement Obligation

The Partnership accounts for its asset retirement obligations in accordance with Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations,* (SFAS 143). SFAS 143 requires the

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Partnership 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.

The Partnership s management has completed the assessment of SFAS 143, and has determined that the Partnership is 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, 2005 or August 31, 2004 because the settlement dates were indeterminable. An asset retirement obligation will be recorded in the periods management can reasonably determine the settlement dates.

Investment in Affiliates

The Partnership owns interests in a number of related businesses that are accounted for using the equity method. In general, the Partnership uses the equity method of accounting for an investment in which there is a 20% to 50% ownership of its outstanding interests and exercises significant influences over its 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 the Partnership 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.

Prior to December 27, 2002 when the remaining 50% of Oasis Pipe Line Company (Oasis) capital stock was redeemed, ETC OLP accounted for its initial 50% ownership in Oasis under the equity method. ETC OLP purchased the remaining 50% interest in Oasis on December 27, 2002 and Oasis became a wholly-owned subsidiary of ETC OLP. The Partnership recognized $1.6 million of equity method income from the investment in Oasis Pipe Line in 2003 prior to the December 27, 2002 acquisition. Oasis results from operations are recognized on a consolidated basis effective January 1, 2003.

The Partnership also owns 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. The Partnership accounts for its investment in Ranger using the equity method of accounting.

As a result of the HPL acquisition (see Note 6), the Partnership acquired a 50% ownership interest in Mid-Texas Pipeline Company (Mid-Texas) which owns a 139-mile 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. The investment is accounted for using the equity method of accounting. The Partnership does not exercise management control over Mid-Texas, and, therefore, the Partnership is precluded from consolidating the Mid-Texas financial statements with those of its own.

On July 18, 2005, the Partnership entered into a joint venture agreement for the purpose of jointly owning and operating a propane cylinder exchange business in metropolitan areas throughout the United States. The Partnership contributed cash of $2,304 and a note payable of $2,000 for its 50% interest in this joint venture. This investment is accounted for using the equity method of accounting.

Goodwill

Goodwill is associated with acquisitions made for the Partnership s midstream, transportation and storage, and retail propane segments. Of the $324,019 balance in goodwill, $27,512 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

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fiscal quarter of 2005, there was no impairment as of August 31, 2005 or 2004. The changes in the carrying amount of goodwill, including the final purchase allocation related to the Energy Transfer Transactions and the ET Fuel Acquisition for the years ended August 31, 2005 and August 31, 2004 were as follows:

	Midstream	Transportation and Storage	Retail Propane	Total
Balance as of August 31, 2003	$ 13,409	$	$	$ 13,409
Goodwill acquired during the year			300,311	300,311
Impairment losses				
Balance as of August 31, 2004	$ 13,409	$	$ 300,311	$ 313,720
Fair value adjustment for final purchase allocation related to the ETC Transactions			(4,842)	(4,842)
Goodwill acquired during the period (including final purchase price adjustments)		10,327	4,814	15,141
Impairment losses				
Balance as of August 31, 2005	$ 13,409	$ 10,327	$ 300,283	$ 324,019

Goodwill acquired during the year includes final purchase price adjustments for acquisitions that occurred prior to the year ended August 31, 2005. The final assessment of asset values related to the Energy Transfer Transaction and the ET Fuel acquisition were not completed until the first and third quarter of fiscal year 2005, respectively. Goodwill related to the ET Fuel acquisition was warranted because this acquisition enhanced the Partnership s current operations and provides synergies to the existing assets owned by the Partnership. The determination of the final fair values resulted in adjustments made in 2005 and consisted of changes from the initially determined values as of June 2, 2004, 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)

As noted in Note 6, the purchase price of HPL has been allocated using the acquisition methodology used by the Partnership when evaluating potential acquisitions. Early indications are that the purchase price may be assigned primarily to depreciable fixed assets or amortizable intangible assets as opposed to goodwill. The Partnership has engaged an appraisal firm to perform the asset appraisal in order to develop a definitive allocation of the purchase price. As a result, the final purchase price allocation may differ from the preliminary allocation. To the extent that the final allocation will result in goodwill, this amount would not be subject to amortization, but would be subject to an annual impairment test and if necessary, written down to a lower fair value should circumstances warrant.

Intangibles and Other Assets

Intangibles and other assets are stated at cost net of amortization computed on the straight-line method. The Partnership eliminates from its 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, 2005		August 31, 2004	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Amortized intangible assets -				
Noncompete agreements (5 to 15 years)	$ 29,278	$ (8,051)	$ 27,952	$ (3,006)
Customer lists (3 to 15 years)	50,148	(6,612)	43,756	(2,307)
Financing costs (3 to 15 years)	17,188	(995)	18,125	(5,515)
Consulting agreements (2 to 7 years)	132	(75)	132	(29)
Other (10 years)	477	(191)	477	(143)
Total	97,223	(15,924)	90,442	(11,000)
Unamortized intangible assets -				
Trademarks	29,447		19,719	
Other assets	1,413		1,260	
Total intangibles and other assets	$ 128,083	$ (15,924)	$ 111,421	$ (11,000)

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Aggregate amortization expense of intangible assets was $9,443, $6,145 and $2,556 for the years ended August 31, 2005, 2004 and the eleven months ended August 31, 2003, respectively. The estimated aggregate amortization expense for the next five fiscal years is $9,296 for 2006; $9,006 for 2007; $7,917 for 2008; $7,064 for 2009, and $5,505 for 2010.

The Partnership reviews amortizable intangible assets for impairment 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, the Partnership reduces the carrying amount of such assets to fair value. The Partnership reviews non-amortizable intangible assets for impairment annually at August 31, or more frequently if circumstances dictate, in accordance with SFAS 144. No impairment of assets intangible assets has been recorded as of August 31, 2005 or 2004.

Accrued and Other Current Liabilities

Accrued and other current liabilities consisted of the following:

	August 31, 2005	August 31, 2004
Interest payable	$ 9,647	$ 6,633
Wages, payroll taxes and employee benefits	23,721	15,975
Taxes other than income	24,615	6,921
Advanced budget payments and unearned revenue	61,851	33,299
Other	26,172	10,656
Accrued and other current liabilities	$ 146,006	$ 73,484

Fair Value

The carrying amounts of accounts receivable and accounts payable approximate their fair value. Based on the estimated borrowing rates currently available to the Partnership and its 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, 2005 was $1,722,519 and $1,715,054 respectively. At August 31, 2004 the aggregate fair value and carrying amount of long-term debt was $1,127,971 and $1,101,828, respectively.

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. The Partnership generates midstream revenues and gross margins principally under fee-based arrangements or other arrangements. Under fee-based arrangements, the Partnership receives 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 its systems and is not directly dependent on commodity prices.

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The Partnership also utilizes other types of arrangements in its 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 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, the Partnership provides 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. Its 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.

Primarily 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, the Partnership s 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 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.

The Partnership accounts for its 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.

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 12). 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.

Shipping and Handling Costs

In accordance with the EITF Issue No. 00-10, *Accounting for Shipping and Handling Fees and Costs,* the Partnership has classified $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, 2005 and August 31, 2004, respectively. Shipping and handling costs related to fuel sold are included in cost of sales. The remaining costs of approximately $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, 2005 and August 31, 2004, respectively. The Partnership does not separately charge shipping and handling costs of propane to customers.

Costs and Expenses

Costs of products sold include actual cost of fuel sold adjusted for the effects of the Partnership s 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.

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Income Taxes

Energy Transfer Partners, L.P. is a limited partnership. As a result, the Partnership s earnings or losses 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 and the taxable income allocation requirements under the Partnership Agreement.

Oasis, Heritage Holdings, and certain other of the Partnership s subsidiaries are taxable corporations and 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.

Income Per Limited Partner Unit

Basic net income per limited partner unit is determined by dividing limited partners interest in net income by the weighted average number of Common Units outstanding (see Note 4). In periods when the Partnership s aggregate net income exceeds the aggregate distributions. EITF 03-6 requires the Partnership to present earnings per unit as if all of the earnings for the periods were distributed (see Notes 4 and 17). 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 Units outstanding and the weighted average number of restricted units (Unit Grants) granted under the Restricted Unit Plan and the 2004 Unit Plan.

Restricted Unit Plan

Effective March 15, 2005 ETP declared a two-for-one split of its Common Units. The units discussed in this footnote are reflected on a post-split basis.

ETP s General Partner, Energy Transfer Partners GP, L.P. (ETP GP) previously adopted the Amended and Restated Restricted Unit Plan dated August 10, 2000, amended February 4, 2002 as the Second Amended and Restated Restricted Unit Plan (the Restricted Unit Plan), for certain directors and key employees of ETP GP and its affiliates. The Restricted Unit Plan provided rights to acquire up to 292,000 Common Units of ETP. The Restricted Unit Plan provided for the award or grant to key employees of the right to acquire Common Units of ETP on such terms and conditions (including vesting conditions, forfeiture or lapse of rights) as the Compensation Committee of ETP GP (the Compensation Committee) shall determine. In addition, eligible directors automatically

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received a director s grant of 1,000 Common Units on each September 1, and newly elected directors were also entitled to receive a grant of 2,000 Common Units upon election or appointment to the Board. Directors who were our employees or employees of ETP GP were not entitled to receive a director s grant of Common Units but could receive Common Units as employees.

Generally, awards granted under the Restricted Unit Plan vested upon the occurrence of specified performance objectives established by the Compensation Committee at the time designations of grants were made, or if later, the three-year anniversary of the grant date. In the event of a change of control (as defined in the Restricted Unit Plan), all rights to acquire ETP Common Units pursuant to the Restricted Unit Plan immediately vested. Pursuant to the January 2004 acquisition of ETP GP by ETE, the change of control provisions of the Restricted Unit Plan were triggered, resulting in the early vesting of 43,200 units by Heritage. Individuals holding 9,000 grants waived their rights to early vesting under the change of control provisions.

The issuance of ETP Common Units pursuant to the Restricted Unit Plan was intended to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation in respect of ETP s Common Units. Therefore, no consideration was payable by the plan participants upon vesting and issuance of ETP s Common Units. Following the June 23, 2004 approval of the 2004 Unit Plan at the special meeting of the Unitholders, the Restricted Unit Plan was terminated (except for the obligation to issue Common Units at the time the 16,592 grants previously awarded vest), and no additional grants have been or will be made under the Restricted Unit Plan. During fiscal year 2005, 4,333 of these previously granted awards vested and Common Units were issued.

Long-Term Incentive Plan

Effective September 1, 2000, ETP GP adopted a long-term incentive compensation plan whereby units were to be awarded to the Executive Officers of ETP GP upon achieving certain targeted levels of Distributed Cash (as defined in the Long-Term Incentive Plan) per unit. Awards under the program were made starting in 2003 based upon the average of the prior three years Distributed Cash per unit. A minimum of 500,000 units on a post-split basis and if targeted levels were achieved, a maximum of 1,000,000 units were available for award under the Long Term Incentive Plan. In connection with the acquisition by ETE of ETP GP in January 2004, 300,036 units vested and Common Units were issued, and the Long-Term Incentive Plan was terminated. No deferred compensation expense was recognized under the long-term incentive plan for the year ended August 31, 2004 or for the eleven months ended August 31, 2003 by the Partnership. Deferred compensation expense was recognized by Heritage on the awards that vested.

2004 Unit Plan

On June 23, 2004 at a special meeting of ETP s Common Unitholders, the Common Unitholders approved the terms of the Partnership s 2004 Unit Plan (the Plan), which provides for awards of ETP Common Units and other rights to the Partnership s employees, officers, and directors. The maximum number of Common Units that may be granted under this Plan is 1,800,000 total units issued. Any awards that are forfeited or which expire for any reason, or any units which are not used in the settlement of an award will be available for grant under the Plan. Units to be delivered upon the vesting of awards granted under the Plan may be (i) units acquired by the Partnership in the open market, (ii) units already owned by the Partnership or its General Partner, (iii) units acquired by the Partnership or its General Partner directly from the Partnership, or any other person, (iv) units that are registered under a registration statement for this Plan, (v) Restricted Units, or (vi) any combination of the foregoing.

Employee Grants. The Compensation Committee, in its discretion, may from time to time grant awards to any employee, upon such terms and conditions as it may determine appropriate and in accordance with specific general guidelines as defined by the Plan. All outstanding awards

shall fully vest into units upon any Change in Control as defined by the Plan, or upon such terms as the Compensation Committee may require at the time the award is granted. As of August 31, 2004, no grants of awards had been made to any employee under the 2004 Unit Plan. During fiscal 2005, awards totaling 273,200 units were made under the 2004 Unit Plan to employees, including executive officers and 7,600 were forfeited. These awards will vest subject to vesting over a three-year period based upon the achievement of certain performance criteria. Vested awards will convert into Common Units upon the third anniversary of the measuring date for the grants, which is September 1 of each year. Vesting occurs based upon the total return to the Partnership s Unitholders as compared to a group of Master Limited Partnership peer companies. The issuance of Common Units pursuant to the 2004 Unit Plan is intended to serve as a means of incentive compensation, therefore, no consideration will be payable by the plan participants upon vesting and issuance of the Common Units.

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Director Grants. Each director who is not also (i) a shareholder or a direct or indirect employee of any parent, or (ii) a direct or indirect employee of ETP LLC, the Partnership, or a subsidiary (Director Participant), who is elected or appointed to the Board for the first time shall automatically receive, on the date of his or her election or appointment, an award of up to 2,000 ETP Common Units (the Initial Director s Grant). Commencing on September 1, 2004 and each September 1 thereafter that this Plan is in effect, each Director Participant who is in office on such September 1, shall automatically receive an award of Units equal to $15,000 divided by the fair market value of a Common Units on such date (Annual Director s Grant). Each grant of an award to a Director Participant will vest at the rate of 1/3 per year, beginning on the first anniversary date of the Award; provided however, notwithstanding the foregoing, (i) all awards to a Director Participant shall become fully vested upon a change in control, as defined by the Plan, unless voluntarily waived by such Director Participant, and (ii) all awards which have not yet vested on the date a Director Participant ceases to be a director shall vest on such terms as may be determined by the Compensation Committee. As of August 31, 2005, initial Director s Grants totaling 16,844 units have been made of which 3,999 units vested on August 31, 2005 and 1,610 vested on September 1, 2005 and Common Units were issued. Also on September 1, 2005, Director Grants of 2,460 units were awarded.

Long-Term Incentive Grants. The Compensation Committee may, from time to time, grant awards under the Plan to any executive officer or any employee it may designate as a participant in accordance with general guidelines under the Plan. These guidelines include (i) options to purchase a specified number of units at a specified exercise price, which are clearly designated in the award as either an incentive stock option within the meaning of Section 422 of the Internal Revenue Code, or a non-qualifying stock option that is not intended to qualify as an incentive stock option under Section 422; (ii) Unit Appreciation Rights that specify the terms of the fair market value of the award on the date the unit appreciation right is exercised and the strike price; (iii) units; or (iv) any combination hereof. As of August 31, 2005, there have been no Long-Term Incentive Grants made under the Plan.

This Plan will be administered by the Compensation Committee of the Board of Directors and may be amended from time to time by the Board; provided however, that no amendment will be made without the approval of a majority of the Unitholders (i) if so required under the rules and regulations of the New York Stock Exchange or the Securities and Exchange Commission; (ii) that would extend the maximum period during which an award may be granted under the Plan; (iii) materially increase the cost of the Plan to the Partnership; or (iv) result in this Plan no longer satisfying the requirements of Rule 16b-3 of Section 16 of the Securities and Exchange Act of 1934. This Plan shall terminate no later that the 10th anniversary of its original effective date.

The Partnership follows the fair value recognition provisions of Statement of Financial Accounting Standards No. 123, *Accounting for Stock-based Compensation* (SFAS 123). SFAS 123 requires that significant assumptions be used during the year to estimate the fair value, which includes the risk-free interest rate used, the expected life of the grants under each of the plans and the expected distributions on each of the units granted. The Partnership assumed a weighted average risk free interest rate of 2.87% for the year ended August 31, 2005, in estimating the present value of the future cash flows of the distributions during the vesting period on the measurement date of each grant. The weighted average, fair value at the grant date of the awards outstanding during fiscal 2005 was $17.37. Annual average cash distributions at the grant date were estimated to be $1.65 for the year ended August 31, 2005. The expected life of each grant is assumed to be the minimum vesting period under certain performance criteria of each grant. Deferred compensation recognized under the Restricted Unit Plan and the 2004 Unit Plan was $1,608 and $42 for the years ended August 31, 2005 and 2004, respectively.

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, 2005 represent the actual results in all material respects.

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Some of the other more significant estimates made by management include, but are not limited to, 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.

Accounting for Derivative Instruments and Hedging Activities

The Partnership applies Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities* (SFAS 133) as amended. 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.

The Partnership has established a formal risk management policy in which derivative financial instruments are employed in connection with an underlying asset, liability and/or anticipated transaction. At inception of a hedge, the Partnership formally documents the relationship between the hedging instrument and the hedged item, the risk management objectives, and the methods used for assessing and testing effectiveness. The Partnership also assesses, both at the inception of the hedge and on a quarterly basis, whether the derivatives that are used in its hedging transactions are highly effective in offsetting changes in cash flows. Furthermore, management meets on a weekly basis to assess the creditworthiness of the derivative counterparties to manage against the risk of default. If the Partnership determines that a derivative is no longer highly effective as a hedge, it discontinues hedge accounting prospectively by including changes in the fair value of the derivative in current earnings.

The Partnership utilizes various exchange-traded and over-the-counter commodity financial instrument contracts to limit its exposure to margin fluctuations in natural gas and NGL prices. These contracts consist primarily of futures and swaps. The Partnership designates various futures and certain associated basis contracts as cash flow hedging instruments in accordance with SFAS 133. All derivatives are recognized in the consolidated balance sheet as price risk management assets or liabilities and are measured at fair value. For those instruments 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. The fair value of price risk management assets and liabilities that are designated and documented as cash flow hedges and determined to be effective are recorded through other comprehensive income. The effective portion of the hedge gain or loss is initially reported as a component of other comprehensive income and when the physical transaction settles, any gain or loss previously recorded in other comprehensive income (loss) on the derivative is recognized in cost of sales 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. As of August 31, 2005 and 2004, these hedging instruments had a net fair value of $(84,523) and $85, respectively, which was recorded as price risk management assets and liabilities on the consolidated balance sheet through other comprehensive income. The Partnership reclassified into earnings losses of $26,784 and gains of $3,396 for the years ended August 31, 2005 and 2004, respectively, related to the commodity financial instruments, that were previously reported in accumulated other comprehensive income (loss). The amount of hedge ineffectiveness recognized in income by ETP was a loss of $17,821 and a gain of $895 for the years ended August 31, 2005 and 2004, respectively. The Partnership expects losses of $85,290 to be reclassified into earnings over the next twelve months related to losses currently reported in accumulated other comprehensive income. The majority of the Partnership s derivatives are expected to settle within the next three years.

In the course of normal operations, the Partnership routinely enters into contracts such as forward physical contracts for the purchase and sale of natural gas, propane, and other NGLs that qualify for and are designated as a normal purchase and sales contracts. Such contracts are exempted from the fair value accounting requirements of SFAS 133 and are accounted for using traditional accrual accounting. In connection with the HPL acquisition, the Partnership acquired certain physical forward contracts that contain embedded options. These contracts have not been designated as normal purchases and sales contracts, and therefore, are marked to market in addition to the financial options that offset them. The Black Scholes valuation model was used to estimate the value of these embedded derivatives.

During the quarter ended August 31, 2005, the Partnership adopted a new risk management policy that provides for our marketing operations to execute limited strategies. 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, futures and basis trades. The derivative contracts that are entered into for trading purposes, subject to limits, are recognized on the consolidated balance sheet at fair value, and changes in the fair value of these derivative instruments are recognized in revenue in the consolidated statement of operations.

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Revenues associated with trading activities for the year ended August 31, 2005 were $50,611, including unrealized gains of $47,147.

The market prices used to value the financial derivative transactions reflect management s estimates considering various factors including closing exchange and over-the-counter quotations, and the time value of the underlying commitments.

4. NET INCOME PER LIMITED PARTNER UNIT:

A reconciliation of net income and weighted average units used incomputing basic and diluted earnings per unit is as follows (in thousands, except per unit data). All limited partner unit amounts have been restated to reflect the two-for-one split which was completed March 15, 2005.

	Year Ended August 31, 2005	Year Ended August 31, 2004	Eleven Months Ended August 31, 2003
Net income	$ 349,350	$ 99,152	$ 46,625
Adjustments:			
General Partner s incentive distributions	(38,455)	(6,917)	
General Partner s equity ownership	(6,987)	(2,021)	(932)
Limited Partner s interest in net income	$ 303,908	$ 90,214	$ 45,693
Additional earnings allocation to General Partner (a)	(49,462)		
Net income available to limited partners (a)	$ 254,446	$ 90,214	$ 45,693
Weighted average limited partner units - basic	97,646,351	52,228,742	13,243,474
Limited Partners basic income per unit from continuing operations (a)	$ 1.79	$ 1.62	$ 3.01
Limited Partners basic income per unit from discontinued operations (a)	0.81	0.11	0.44
Basic net income per limited partner unit (a)	$ 2.60	$ 1.73	$ 3.45
Weighted average limited partner units	97,646,351	52,228,742	13,243,474
Dilutive effect of Incentive units	253,926	54,468	
Weighted average limited partner units, assuming dilutive effect of Incentive units	97,900,277	52,283,210	13,243,474
Limited Partners diluted income per unit from continuing operations	$ 1.79	$ 1.62	$ 3.01
Limited Partners diluted income per unit from discontinued operations	0.81	0.11	0.44
Diluted net income per limited partner unit	$ 2.60	$ 1.73	$ 3.45

(a) Basic and diluted net income per limited partner unit have been presented to reflect the application of EITF 03-6. The Partnership s net income for partners capital purposes is allocated to the General Partner and Limited Partners in accordance with their respective partnership percentages, after giving effect to any priority income allocations for incentive distributions, if any, to the Partnership s General

Partner, the holders of the incentive distribution rights pursuant to the Partnership Agreement, which are declared and paid following the close of each quarter. For purposes of computing basic and diluted net income per limited partner unit, in periods, on a year to date basis, when the Partnership s aggregate net income exceeds the aggregate distributions for such year to date 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 the Partnership distributes with respect to any quarter exceeds levels specified in the Partnership Agreement (see Note 12).

5. DISCONTINUED OPERATIONS:

On April 14, 2005, the Partnership completed the sale of its Oklahoma gathering, treating and processing assets, referred to as the Elk City System, for total cash proceeds of $191,606, including certain adjustments as provided for in the purchase and sale agreement. The Partnership sold the Elk City System to allow its management to focus on integrating the Partnership s asset base in Texas including the assets acquired during the last twelve months. The Elk City System was included in the Partnership s midstream segment. The sale resulted in a gain of $142,469 net of income tax expense of $1,829, and the cash proceeds were used to repay a portion of the indebtedness incurred by the Partnership as a result of the acquisition of HPL. The sale of the Elk City System has been accounted for as discontinued operations. 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	Eleven Months Ended August 31, 2003
Revenues	$ 105,542	$ 135,297	$ 92,441
Cost and expenses	(100,044)	(129,134)	(86,447)
Income from discontinued operations	$ 5,498	$ 6,163	$ 5,994

6. ACQUISITIONS:

Fiscal year 2005 acquisitions

In November 2004, the Partnership 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, the Partnership acquired the controlling interests in HPL from American Electric Power Corporation (AEP) for approximately $825,000 subject to working capital adjustments. This acquisition was financed by the Partnership through a combination of cash on hand, borrowings under its current credit facilities and a private placement with institutional investors of $350,000 of Partnership Common Units. In addition, the Partnership acquired working inventory of natural gas stored in the Bammel storage facilities and financed it through a short-term borrowing from an affiliate. 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. Under the terms of the transaction, the Partnership, through ETC OLP, its wholly-owned subsidiary, acquired all but a 2% limited partner interest in HPL. The HPL System is comprised 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 the Partnership to expand its current transportation systems into areas where it

previously did not have a presence, and in combination with the Partnership s current midstream assets, provides the premier producing basins in Texas with direct access to the Houston Ship Channel corridor. HPL is included in the 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

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Vantex Gas system is located in East Texas and is comprised 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 fiscal 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.

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 (in thousands):

	Texas Chalk and Madison Systems November 2004	HPL 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	1	584
Other current assets		8,672		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

The purchase prices have been allocated based on the fair values of the assets acquired and liabilities assumed at the date of an acquisition. The preliminary allocation may be adjusted to reflect the final purchase price allocation which will be based on an independent appraisal, if applicable.

During the third fiscal quarter of 2005 the Partnership completed a verification of the working gas inventory contained in the storage facilities it had acquired in two acquisitions and has adjusted the preliminary allocations of the purchase prices to reflect the verified amounts. The Partnership has also adjusted the preliminary allocations to reflect working capital settlement with AEP occurring in the fourth fiscal quarter of 2005. The Partnership continues to have discussions with AEP regarding the inventory verification and certain working capital matters, and further adjustments may be necessary following an independent appraisal of fair market values, completion of the working capital and inventory settlement, and other adjustments made in accordance with the purchase and sale agreement.

The Partnership recorded the following intangible assets in conjunction with these acquisitions as of August 31, 2005:

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 acquired	$ 11,946

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

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 are expected to provide significant growth opportunities for the Partnership going forward. The acquisition was accounted for using the purchase method. The purchase price has been 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 2005 upon the completion of an independent appraisal.

The unaudited pro forma results of operations as if the ET Fuel System had been acquired at the beginning of the periods presented are presented in Note 2 to the consolidated financial statements.

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.

Fiscal year 2003 acquisitions

In October 2002, ETC OLP purchased certain operating assets from Aquila Gas Pipeline, primarily natural gas gathering, treating and processing assets in Texas and Oklahoma, for $263,676 in cash.

On December 27, 2002, Oasis Pipe Line Company redeemed the remaining 50% of its capital stock owned by Dow Hydrocarbons Resources, Inc. for $87,000 and cancelled the stock which resulted in ETC OLP owning 100% of the capital stock of Oasis Pipe Line Company effective December 27, 2002.

Also, on December 27, 2002, ETC OLP Holdings, LP, a limited partner of La Grange Energy, contributed ET Company I to the Partnership. The investment in the Vantex system was included in the assets contributed.

Assets acquired and purchase price allocation

The assets acquired and purchase price allocation of the Partnership s acquisitions for the years ended August 31, 2004 and August 31, 2003 were as follows:

	Oasis December 27, 2002	ET Fuel System June 2, 2004	Aquila Gas Pipeline October 2002	HOLP acquisitions (aggregated) January 20, 2004 to August 31, 2004
Accounts receivable	$	$	$	$ 1,612
Inventory			1,626	335
Other current assets		57	194	
Investment in unconsolidated affiliate			51,270	
Property, plant and equipment	134,040	499,789	208,374	8,024
Intangibles				1,560
Goodwill		10,327		5,437
Total assets acquired	134,040	510,173	261,464	16,968
Accounts payable				
Accrued expenses		(758)	(2,788)	(52)
Other current liabilities				(1)
Deposits from vendor		(750)		
Exchanges payable		(10,094)		
Long-term debt				(215)
Deferred taxes - noncurrent	(47,040)			
Total liabilities assumed	(47,040)	(11,602)	(2,788)	(268)
Net assets acquired	$ 87,000	$ 498,571	$ 258,676	$ 16,700

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Each of these acquisitions was accounted for as a business combination using the purchase method of accounting in accordance with the provisions of SFAS 141, and each 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 respective acquisition. The results of operations for these acquisitions are included in the consolidated statement of operations from the date of the respective acquisition.

7. WORKING CAPITAL FACILITY AND LONG-TERM DEBT:

Long-term debt consists of the following:

	August 31, 2005	August 31, 2004	Maturities
Senior Notes:			
2005 5.95% Senior Notes, net of discount of $2,160	$ 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 $412	$ 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	$ 72,000	$ 84,000	Annual payments of $12,000 due each June 30, 2002 through 2011. Interest is paid quarterly.
1997 Medium Term Note Program:			
7.17% Series A Senior Secured Notes	12,000	12,000	Annual payments of $2,400 due each November 19, 2005 through 2009. Interest is paid semi-annually.
7.26% Series B Senior Secured Notes	16,000	18,000	Annual payments of $2,000 due each November 19, 2003 through 2012. Interest is paid semi-annually.
6.50% Series C Senior Secured Notes	714	1,786	Annual payments of $357 due on March 13, 2006 and 2007. Interest is paid semi-annually.

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	August 31, 2005	August 31, 2004	Maturities
HOLP Senior Secured Notes:			
2000 and 2001 Senior Secured Promissory Notes:			
8.47% Series A Senior Secured Notes	6,400	9,600	Annual payments of $3,200 due each August 15, 2003 through 2007. Interest is paid quarterly.
8.55% Series B Senior Secured Notes	22,857	27,429	Annual payments of $4,571 due each August 15, 2004 through 2010. Interest is paid quarterly.
8.59% Series C Senior Secured Notes	27,000	27,000	Annual payments of $5,750 due each August 15, 2006 and 2007, $4,000 due August 15, 2008, and $5,750 due each August 15, 2009 through 2010. Interest is paid quarterly.
8.67% Series D Senior Secured Notes	58,000	58,000	Annual payments of $12,450 due each August 15, 2008 and 2009, $7,700 due on 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	Annual payments of $3,636 due each August 15, 2010 through 2020. Interest is paid quarterly.
7.21% Series G Senior Secured Notes	11,400	15,200	Annual payments of $3,800 due each May 15, 2004 through 2008. Interest is paid quarterly.
7.89% Series H Senior Secured Notes	8,000	8,000	Annual payments of $727 due each May 15, 2006 through 2016. Interest is paid quarterly.
7.99% Series I Senior Secured Notes	16,000	16,000	One payment of $16,000 due on May 15, 2013. Interest is paid quarterly.
ETC OLP Term Loan Facility		725,000	Repaid in January, 2005 see 2005 Senior Notes below.
HOLP Senior Revolving Acquisition Facility	42,000	23,000	Available through December 31, 2006 see terms below under Revolving Credit Facilities .
Revolving Credit Facility	186,000		Available through January 2010 see terms below under Revolving Credit Facilities .
Revolving Credit Facility Swingline loan option	15,000		Available through January 2010 see terms below under Revolving Credit Facilities .
Long term portion of the Senior Revolving Working Capital Facility	9,642	10,000	Available through December 31, 2006 see terms Below under Revolving Credit Facilities .
Notes Payable on noncompete agreements with interest imputed at rates averaging 7.48%	15,284	18,218	Due in installments through 2014.
Other	2,325	1,595	Due in installments through 2024.
Current maturities of long-term debt	(39,349)	(30,957)	
	$ 1,675,705	$ 1,070,871	

All receivables, contracts, equipment, inventory, general intangibles, cash concentration accounts, and the capital stock of HOLP and its subsidiaries secure the Senior Secured, Medium Term, and Senior Secured Promissory Notes. In addition to the stated interest rate for the Notes, the Partnership is 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, 2005 the Notes were rated investment grade or better thereby alleviating the requirement that HOLP pay the additional 1% interest.

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2005 Senior Notes

On January 18, 2005, in a Rule 144A private placement offering, the Partnership issued $750,000 in aggregate principal amount of its 5.95% Senior Notes due on February 1, 2015 (the 2015 Unregistered Notes). The Partnership recorded a discount of $2,265 and debt issue costs of $7,375 in connection with the issuance of 2015 Unregistered Notes. The net proceeds of approximately $741,000 were used to repay the indebtedness and accrued interest outstanding under the then existing ETC OLP credit facilities that were previously secured by the assets of ETC OLP. As a result of the repayment, the Partnership wrote off $7,996 in deferred financing costs and accounted for the write-off as loss on extinguishment of debt. On July 29, 2005, the Partnership completed a registered exchange offer to exchange newly issued 5.95% Senior Notes due 2015 which have been registered under the Securities Act of 1933 (the New Notes), for a like amount of outstanding 5.95% Senior Notes due 2015, which have not been registered under the Securities Act (the Old Notes). The sole purpose of the exchange offer was to fulfill the obligations of the Partnership under the registration rights agreement entered into in connection with the sale by the Partnership of the Old Notes. The New Notes issued pursuant to the exchange offer have substantially identical terms to the Old Notes.

On July 29, 2005 the Partnership completed an offering pursuant to Rule 144A and Regulation S under the Securities Act of 1933, whereby the Partnership issued $400,000 in aggregate principal amount of 5.65% Senior Notes due 2012 (the 2012 Unregistered Notes and together with the 2015 Unregistered Notes, the ETP Senior Notes). The Partnership recorded a discount of $412 and debt issue costs of $2,840 in conjunction with the 2012 Unregistered Notes. The ETP Senior Notes, are fully and unconditionally guaranteed by ETC OLP and its designated subsidiaries.

ETC OLP and its designated subsidiaries act as the guarantor of the debt obligations for the 2015 Unregistered Notes issued on January 18, 2005 and the 2012 Unregistered Notes issued on July 29, 2005. If the Partnership 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.

Revolving Credit Facilities

Effective January 18, 2005, the Partnership entered into an unsecured Revolving Credit Facility. The terms of the agreement are as follows:

A $700,000 unsecured Revolving Credit Facility available through January 18, 2010. Amounts borrowed under the Revolving Credit Facility bear interest at a rate based on either a Eurodollar rate, or a prime rate. Effective June 2, 2005, the Partnership increased the unsecured Revolving Credit Facility from $700,000 to $800,000. The Revolving Credit Facility also offers a Swingline loan option with the maximum borrowing of $30,000 at a daily rate based on the London market. The weighted average interest rate was 4.827% as of August 31, 2005. The maximum commitment fee payable on the unused portion of the facility is 0.30%. The Partnership borrowed $475,000 under the Revolving Credit Facility to fund a portion of the HPL acquisition in January 2005. As of August 31, 2005, $201,000 was outstanding under the Revolving Credit Facility which includes $15,000 under the Swingline option and also had outstanding Letters of Credit of $11,300. Letter of Credit exposure plus the Revolving Credit Facility cannot exceed the $800,000 maximum Revolving Credit Facility. Total amount available under the Credit Agreement as of August 31, 2005 was $587,700.

ETC OLP and its designated subsidiaries act as the guarantor of the Revolving Credit Facility. If the Partnership were to default, ETC OLP and the other guarantors would be responsible for full repayment of this obligation. The Revolving Credit Facility is unsecured and has equal rights to holders of the Partnership s other current and future unsecured debt.

Effective March 31, 2004, HOLP entered into the Third Amended and Restated Credit Agreement. The terms of the Agreement are as follows:

A $75,000 Senior Revolving Working Capital Facility is available through December 31, 2006. Amounts borrowed under the Working Capital Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The weighted average interest rate was 5.308% for the amount outstanding at August 31, 2005. The maximum commitment fee payable on the unused portion of

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the facility is 0.50%. HOLP must reduce the principal amount of working capital borrowings to $10,000 for a period of not less than 30 consecutive days at least one time during each fiscal year. All receivables, contracts, equipment, inventory, general intangibles, cash concentration accounts of HOLP, and the capital stock of HOLP s subsidiaries secure the Senior Revolving Working Capital Facility. As of August 31, 2005, the Senior Revolving Working Capital Facility had a balance outstanding of $26,668, of which $9,642 was long-term and $17,026 was short-term. A $5,000 Letter of Credit issuance is available to HOLP for up to 30 days prior to the maturity date of the Working Capital Facility. HOLP completed the 30-day clean down requirement under its Senior Revolving Working Capital Facility on June 14, 2005 and had outstanding Letters of Credit of $1,002 at August 31, 2005. Letter of Credit Exposure plus the Working Capital Loan cannot exceed the $75,000 maximum Working Capital Facility.

A $75,000 Senior Revolving Acquisition Facility is available through December 31, 2006. Amounts borrowed under the Acquisition Credit Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The weighted average interest rate was 5.182% for the amount outstanding at August 31, 2005. The maximum commitment fee payable on the unused portion of the facility is 0.50%. All receivables, contracts, equipment, inventory, general intangibles, cash concentration accounts of HOLP, and the capital stock of HOLP s subsidiaries secure the Senior Revolving Acquisition Facility. As of August 31, 2005, the Senior Revolving Acquisition Facility had a balance outstanding of $42,000.

Effective September 1, 2005, HOLP entered into the Second Amendment to the Third Amended and Restated Credit Agreement. The amendment in its entirety states as follows: In no event shall the Letter of Credit Exposure exceed $15,000 at any time . All of the remaining terms, provisions and conditions of the existing Credit Agreement continue in full force and effect as within the March 31, 2004 Third Amended and Restated Credit Amendment noted above.

The agreements for each of the Senior Secured Notes, Medium Term Note Program, Senior Secured Promissory Notes, and the HOLP s bank credit facilities contain customary restrictive covenants applicable to HOLP, including limitations on substantial disposition of assets, changes in ownership of HOLP the level of additional indebtedness and creation of liens. These covenants require HOLP to maintain ratios of Consolidated Funded Indebtedness to 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 the HOLP s 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 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.

In addition, the Indenture relating to the Senior Notes issued on January 18, 2005 and the Revolving Credit Facility contain various covenants related to our ability to incur certain indebtedness, grant certain liens, enter into certain merger, sale or consolidation transactions, enter into sale-lease back transactions, and make certain investments. The Revolving Credit Facility also requires the Partnership to maintain ratios of Consolidated Funded Indebtedness to Consolidated EBITDA (as similarly defined in the Revolving Credit Agreement) of not more than 4.50 to 1 at any time other than during a Specified Acquisition Period (as similarly defined in the Revolving Credit Agreement) and 5.00 to 1 during a Specified Acquisition Period. The ratio of Consolidated EBITDA for each period of four consecutive fiscal quarters, to Consolidated Interest Expense (as similarly defined in the Revolving Credit Agreement), will never be less than 3.00 to 1.

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Failure to comply with the various restrictive and affirmative covenants of the HOLP s bank credit facilities and the Note Agreements could negatively impact the Operating Partnerships ability to incur additional debt and/or the Partnership s ability to pay distributions. The Partnership and HOLP 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, 2005.

Future maturities of long-term debt for each of the next five fiscal years and thereafter are $39,349 in 2006; $90,996, in 2007; $46,127 in 2008; $43,282 in 2009; $241,793 in 2010, and $1,253,507 thereafter.

8. INCOME TAXES:

The components of the federal and state income tax provision (benefit) of the Partnership s taxable subsidiaries is summarized as follows:

	Year Ended August 31, 2005	Year Ended August 31, 2004	Eleven Months Ended August 31, 2003
Current provision:			
Federal	$ 5,043	$ 6,505	$ 5,548
State	963	830	
Total	$ 6,006	$ 7,335	$ 5,548
Deferred provision:			
Federal	882	(2,677)	(1,116)
State	407	(177)	
Total	$ 1,289	$ (2,854)	$ (1,116)
Total tax provision before gain on discontinued operations	$ 7,295	$ 4,481	$ 4,432
Gain on discontinued operations:			
Current provision:			
Federal	$ 1,570	$	$
State	259		
Total	$ 1,829	$	$
Total tax provision	$ 9,124	$ 4,481	$ 4,432
Effective tax rate	2.55%	4.32%	8.68%

The effective tax rate differs from the statutory rate due primarily to Partnership earnings that are not subject to federal and state income taxes at the partnership level. The difference between the statutory rate and the effective rate is summarized as follows:

	Year Ended August 31, 2005	Year Ended August 31, 2004	Eleven Months Ended August 31, 2003
Federal statutory tax rate	35.00%	35.00%	35.00%
State income tax rate net of federal benefit	3.56%	3.96%	
Increase (decrease) as a result of:			
Partnership earnings not subject to tax	(36.25)%	(31.08)%	(26.32)%
Corporate subsidiary earnings not subject to state tax	(0.02)%	(3.56)%	
Franchise and other taxes not measured on income	0.26%		
Effective tax rate	2.55%	4.32%	8.68%

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Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. The components of the deferred tax liability were as follows:

	August 31, 2005	August 31, 2004
Property, plant and equipment	$ 109,896	$ 108,661
Other	1,289	1,235
	$ 111,185	$ 109,896

9. MAJOR CUSTOMERS AND SUPPLIERS

The Partnership had gross sales as a percentage of total revenues to nonaffiliated major customers as follows:

	Year Ended August 31, 2005	Year Ended August 31, 2004	Eleven Months Ended August 31, 2003
Midstream and transportation and storage segment:			
BP Energy Company	17.8%	11.6%	less than 10%
Houston Pipeline Company	n/a	11.2%	11.1%
Dow Hydrocarbon and Resources, Inc.	less than 10%	10.7%	18.6%

The Partnership s major customers are in the midstream and transportation and storage segments. The Partnership s natural gas operations have a concentration of customers in natural gas transmission, distribution and marketing, as well as industrial end-users while its NGL operations have a concentration of customers in the refining and petrochemical industries. These concentrations of customers may impact the Partnership s overall exposure to credit risk, either positively or negatively. The Houston Pipeline Company had been a major customer to the Partnership previous to its acquisition in fiscal year 2005 (see Note 6). As of August 31, 2005 and 2004 the Partnership had a receivable due from BP Energy Company that was 11% and 15%, respectively, of the Partnership s total midstream and transportation and storage segment accounts receivable. However, management believes that the Partnership s portfolio of accounts receivable is sufficiently diversified to minimize any potential credit risk. No single customer accounts for 10% or more of ETP s transportation and storage or propane revenues. The Partnership had gross segment purchases as a percentage of total purchases from major suppliers as follows:

	Year Ended August 31, 2005	Year Ended August 31, 2004	Eleven Months Ended August 31, 2003
Midstream and transportation and storage segment:			
Unaffiliated			
BP Energy Company	16.0%	11.0%	less than 10%
Burlington Resources	less than 10%	less than 10%	10.1%
Propane segments (a)			
Unaffiliated			
Enterprise	23.7%	22.5%	

Dynegy	20.6%	21.8%
Affiliated		
M.P. Oils, Ltd.	15.4%	21.0%

(a) Purchases from major suppliers in the propane segment represent amounts purchased from January 20, 2004 through August 31, 2004. If the Energy Transfer Transactions had occurred at the beginning of the periods presented, the percentages purchased from Enterprise, Dynegy and MP Oils Ltd. would have been 24.9%, 18.8%, and 19%, respectively for the year ended August 31, 2004.

These concentrations of suppliers may impact the Partnership s overall operations either positively or negatively. However, management believes that the diversification of suppliers is sufficient to enable the Partnership to purchase all of its supply needs at market prices without a material disruption of operations if supplies are interrupted from any of our existing sources. Although no assurances can be given that supplies of natural gas, propane and NGLs will be readily available in the future, we expect a sufficient supply to continue to be available.

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10. COMMITMENTS AND CONTINGENCIES:

Commitments

Certain property and equipment is leased under noncancelable leases, which require fixed monthly rental payments and expire at various dates through 2020. Rental expense under these leases totaled approximately $8,830, $4,283 and $881 for the years ended August 31, 2005, 2004, and the eleven months ended August 31, 2003, respectively, and has been included in operating expenses in the accompanying statements of operations. Fiscal year future minimum lease commitments for such leases are $5,881 in 2006; $3,231 in 2007; $2,204 in 2008; $1,901 in 2009; $1,397 in 2010 and $978 thereafter.

The Partnership has forward commodity contracts, which will be settled by physical delivery. Short-term contracts, which expire in less than one year, require delivery of up to 567 MMBtu/d. Long-term contracts require delivery of up to 416 MMBtu/d. The long-term contracts run through July 2018.

In connection with the acquisition of the ET Fuel System in June of 2004, the Partnership entered into an eight-year transportation and storage agreement with TXU Portfolio Management Company, LP (TXU Shipper) to transport a minimum of 115.6 MMBtu per year. The Partnership 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, the Partnership was 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, the Partnership recognized an additional $14,716 in fees during the third fiscal quarter of 2005. TXU Shipper has notified the Partnership that is has elected to reduce the minimum transport volume to 100.0 MMBtu per year beginning in January 2006.

The Partnership has signed long-term agreements with several parties committing firm transportation volumes into the East Texas Pipeline which is part of the East Texas Pipeline System. Those commitments include an agreement with XTO Energy Inc. (XTO) to deliver approximately 200 MMBtu/d of natural gas into the pipeline. The term of the XTO agreement began in June 2004 when the pipeline became operational and expires in June 2012.

During 2005, the Partnership entered into two new long-term agreements committing firm transportation volumes on certain of the Partnership s transportation pipelines. The two contracts will require an aggregated capacity of approximately 238 MMBtu/d of natural gas and extends through 2011.

In connection with the HPL acquisition in January 2005, the Partnership acquired a sales agreement whereby the Partnership is committed to sell minimum amounts of gas ranging from 20 MMBtu/d to 50 MMBtu/d to a single customer. Future annual minimum sale volumes remaining under the agreement are approximately 9.9 billion Btu/d, and 6.9 billion Btu/d for the years ended August 31, 2006, and 2007, respectively. The Partnership also assumed a contract with a service provider which obligates ETP to obtain certain compressor, measurement and other services through 2007 with monthly payments of approximately $1,700.

The Partnership in the normal course of business, purchases, processes and sells natural gas pursuant to long-term contracts. Such contracts contain terms that are customary in the industry. The Partnership believes that such terms are commercially reasonable and will not have a material adverse effect on the Partnership s financial position or results of operations.

The Partnership has entered into several propane purchase and supply commitments with varying terms as to quantities and prices, which expire at various dates through March 2006.

Litigation

The Partnership s midstream operating partnership, ETC OLP, may, from time to time, be involved in litigation and claims arising out of its operations in the normal course of business. In addition, management is not aware of any material legal or governmental proceedings against ETC OLP or contemplated to be brought against ETC OLP, under the various environmental protection statutes to which it is 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.

Propane is a flammable, combustible gas. Serious personal injury and significant property damage can arise in connection with its storage, transportation or use. In the ordinary course of business, HOLP is sometimes threatened

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with or are named as a defendant in various lawsuits seeking actual and punitive damages for product liability, personal injury and property damage. ETP maintains liability insurance with insurers in amounts and with coverages and deductibles management believes are reasonable and prudent, and which are generally accepted in the industry. However, there can be no assurance that the levels of insurance protection currently in effect will continue to be available at reasonable prices or that such levels will remain adequate to protect us from material expenses related to product liability, personal injury or property damage in the future. Although any litigation is inherently uncertain, based on past experience, the information currently available and the availability of insurance coverage, we do not believe that pending or threatened litigation matters will have a material adverse effect on our financial condition or results of operations.

Of the pending or threatened matters in which the ETP or its subsidiaries are a party, none have arisen outside the ordinary course of business except for an action filed by HOLP on November 30, 1999 against SCANA Corporation, Cornerstone Ventures, L.P. and Suburban Propane, L.P. (the SCANA litigation). Prior to trial, a settlement was reached with Defendant Cornerstone Ventures, L.P., and they were dismissed from the litigation. On October 21, 2004, HOLP announced that it received a favorable jury verdict with respect to the SCANA litigation. The jury found in favor of HOLP on all four claims against SCANA, awarding a total of $48 million in actual and punitive damages. SCANA has appealed the jury s decision, and currently, the parties are involved in the appeal of a number of post-trial motions. ETP cannot predict whether the final judgment will affirm the jury verdict without any modification. Because of the uncertainty of the final determination and the net amount of funds ETP could receive, the Partnership cannot predict whether it will receive any of the damages awarded. The Partnership is entitled to a portion of that award only to the extent that ETP distributes any of the award funds to its Common Unitholders. As a result, management cannot yet predict whether the Partnership will receive any of the damages awarded by this verdict.

The Partnership or its subsidiaries is a party to various legal proceedings and/or regulatory proceedings incidental to its business. Certain claims, suits and complaints arising in the ordinary course of business have been filed or are pending against ETP. In the opinion of management, all such matters are either covered by insurance, are without merit or involve amounts, which, if resolved unfavorably, would not have a significant effect on the financial position or results of operations of the Partnership. 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, ETP accrues the related deductible. As of August 31, 2005 and 2004, an accrual of $1,120 and $930, respectively was recorded as accrued and other current liabilities on the Partnership s consolidated balance sheet.

Environmental

The Partnership s operations are subject to extensive federal, state and local environmental laws and regulations that require expenditures for remediation at operating facilities and waste disposal sites. Although ETP believes its operations are in substantial compliance with applicable environmental laws and regulations, risks of additional costs and liabilities are inherent in the natural gas pipeline and processing business, and there can be no assurance that significant costs and liabilities will not be incurred. Moreover, it is possible that other developments, such as increasingly stringent environmental laws, regulations and enforcement policies thereunder, and claims for damages to property or persons resulting from the operations, could result in substantial costs and liabilities. Accordingly, the Partnership has adopted policies, practices, and procedures in the areas of pollution control, product safety, occupational health, and the handling, storage, use, and disposal of hazardous materials to prevent material environmental or other damage, and to limit the financial liability, which could result from such events. However, some risk of environmental or other damage is inherent in the natural gas pipeline and processing business, as it is with other entities engaged in similar businesses.

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In conjunction with the October 1, 2002 acquisition of the Texas and Oklahoma natural gas gathering and gas processing assets from Aquila Gas Pipeline, Aquila, Inc. agreed to indemnify ETC OLP for any environmental liabilities that arose from the operation of the assets for the period prior to October 1, 2002. Aquila also agreed to indemnify ETC OLP for 50% of any environmental liabilities that arose from the operations of Oasis Pipe Line Company prior to October 1, 2002.

The Partnership also assumed certain environmental remediation matters related to eleven sites in connection with its acquisition of HPL.

Petroleum-based contamination or environmental wastes are known to be located on or adjacent to six sites, on which HOLP presently has, or formerly had, retail propane operations. These sites were evaluated at the time of their acquisition. In all cases, remediation operations have been or will be undertaken by others, and in all six cases, HOLP obtained indemnification for expenses associated with any remediation from the former owners or related entities. ETP has not been named as a potentially responsible party at any of these sites, nor has the Partnership s operations contributed to the environmental issues at these sites. Accordingly, no amounts have been recorded in the Partnership s August 31, 2005 or its August 31, 2004 balance sheets. Based on information currently available to the Partnership, such projects are not expected to have a material adverse effect on the Partnership s financial condition or results of operations.

In July 2001, HOLP acquired a company that had previously received a request for information from the U.S. Environmental Protection Agency (the EPA) regarding potential contribution to a widespread groundwater contamination problem in San Bernardino, California, known as the Newmark Groundwater Contamination. Although the EPA has indicated that the groundwater contamination may be attributable to releases of solvents from a former military base located within the subject area that occurred long before the facility acquired by HOLP was constructed, it is possible that the EPA may seek to recover all or a portion of groundwater remediation costs from private parties under the Comprehensive Environmental Response, Compensation, and Liability Act (commonly called Superfund). Based upon information currently available to HOLP, it is believed that HOLP s liability if such action were to be taken by the EPA would not have a material adverse effect on the Partnership s financial condition or results of operations.

Environmental exposures and liabilities are difficult to assess and estimate due to unknown factors such as the magnitude of possible contamination, the timing and extent of remediation, the determination of the Partnership s liability in proportion to other parties, improvements in cleanup technologies and the extent to which environmental laws and regulations may change in the future. Although environmental costs may have a significant impact on the results of operations for any single period, the Partnership believes that such costs will not have a material adverse effect on its financial position. As of August 31, 2005 and 2004, an accrual on an undiscounted basis of $2,036 and $845, respectively, was recorded in the Partnership s consolidated balance sheet to cover material environmental liabilities including certain matters assumed in connection with the HPL acquisition. A receivable of $404 and $423 was recorded in the Partnership s balance sheets as of August 31, 2005 and August 2004, respectively, to account for Aquila s share of certain environmental liabilities.

11. PRICE RISK MANAGEMENT ASSETS AND LIABILITIES:

Commodity Price Risk

The Partnership is exposed to market risks related to the volatility of natural gas and NGL prices. To reduce the impact of this price volatility, the Partnership primarily uses derivative commodity instruments (futures and swaps) to manage its exposures to fluctuations in margins. The fair value of all price risk management assets and liabilities that are designated and documented as cash flow hedges and determined to be effective are recorded through other comprehensive income (loss) until the settlement month. When the physical transaction settles, any gain or loss previously recorded in other comprehensive income (loss) on the derivative is recognized in costs of products sold in the statement of operations.

Unrealized gains or losses on price risk management assets and liabilities related to non-trading activities that do not meet the requirements for hedge accounting are recognized in costs of products sold in the consolidated statement of operations.

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The Partnership s price risk management assets and liabilities as of August 31, 2005 and 2004 were as follows:

	Commodity	Notional Volume MMBTU	Maturity	Fair Value
August 31, 2005:				
Mark to Market Derivatives				
(Non-Trading)				
Basis Swaps IFERC/Nymex	Gas	(16,775,767)	2005	$ (5,462)
Basis Swaps IFERC/Nymex	Gas	(15,377,347)	2006	5,524
Basis Swaps IFERC/Nymex	Gas	(2,043,000)	2007	584
				$ 646
Swing Swaps IFERC	Gas	(11,986,504)	2005	$ (6,580)
Swing Swaps IFERC	Gas	(13,650,000)	2006	180
				$ (6,400)
Fixed Swaps/Futures	Gas	(2,150,000)	2005	$ (8,562)
Fixed Swaps/Futures	Gas	190,000	2006	1,139
				$ (7,423)
Options	Gas	416,000	2005	$ 17,552
Options	Gas	(730,000)	2006	46,951
Options	Gas	(730,000)	2007	15,772
Options	Gas	(732,000)	2008	(1,334)
				$ 78,941
Forward Physical Contracts	Gas	(5,578,000)	2005	$ (17,552)
Forward Physical Contracts	Gas	(10,730,000)	2006	(46,951)
Forward Physical Contracts	Gas	(4,300,000)	2007	(15,772)
Forward Physical Contracts	Gas	(732,000)	2008	1,334
				$ (78,941)
(Trading)				
Basis Swaps IFERC/Nymex	Gas	(24,917,500)	2005	$ 30,815
Basis Swaps IFERC/Nymex	Gas	(30,855,000)	2006	15,804
Basis Swaps IFERC/Nymex	Gas		2007	3,214
				$ 49,833
Swing Swaps IFERC	Gas	(26,345,000)	2005	$ (3,648)
Swing Swaps IFERC	Gas	(32,354,999)	2006	(52)
Swing Swaps IFERC	Gas	5,475,000	2007	14
Swing Swaps IFERC	Gas	11,020,000	2008	
				$ (3,686)
Fixed Swaps/Futures	Gas	(150,000)	2005	$ 559
Forward Physical Contracts	Gas		2005	$ 441

Cash Flow Hedging Derivatives				
Fixed Swaps/Futures	Gas	(28,930,000)	2005	$ (110,127)
Fixed Swaps/Futures	Gas	(13,137,500)	2006	(31,677)
Fixed Swaps/Futures	Gas	240,000	2007	662
				$ (141,142)
Fixed Index Swaps	Gas	2,640,000	2005	$ 15,628
Fixed Index Swaps	Gas	3,270,000	2006	20,827
				$ 36,455
Basis Swaps IFERC/Nymex	Gas	(6,412,500)	2005	$ 3,172
Basis Swaps IFERC/Nymex	Gas	(465,000)	2006	189
				$ 3,361
August 31, 2004:				
Mark to Market Derivatives				
Basis Swaps IFERC/Nymex	Gas	(6,265,000)	2004	$ 1,380
Basis Swaps IFERC/Nymex	Gas	(1,810,000)	2005	696
				$ 2,076
Swing Swaps IFERC	Gas	4,180,000	2004	$ (44)
Swing Swaps IFERC	Gas	71,550,000	2005	349
				$ 305
Futures Nymex	Gas	2,087,500	2004	$ 614
Futures Nymex	Gas		2005	
				$ 614
Cash Flow Hedging Derivatives				
Basis Swaps IFERC/Nymex	Gas	240,000	2004	$ (56)
Basis Swaps IFERC/Nymex	Gas	(460,000)	2005	24
				$ (32)
Futures Nymex	Gas	(4,377,500)	2004	$ 694
Futures Nymex	Gas	(330,000)	2005	322
				$ 1,016
		Barrels		
NGL Swaps	Condensate, Propane, Ethane	160,000	2004	$ 108
NGL Swaps	Condensate,	90,000	2005	(194)
				$ (86)

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Estimates related to the Partnership s gas marketing activities are sensitive to uncertainty and volatility inherent in the energy commodities markets and actual results could differ from these estimates. The Partnership also attempts to maintain balanced positions in its non-trading activities to protect itself from the volatility in the energy commodities markets; however, net unbalanced positions can exist. Long-term physical contracts are tied to index prices. System gas, which is also tied to index prices, will provide the gas required by our long-term physical contracts. When third-party gas is required to supply long-term contracts, a hedge is put in place to protect the margin on the contract. Financial contracts, which are not tied to physical delivery, will be offset with financial contracts to balance the Partnership s positions. To the extent open commodity positions exist, fluctuating commodity prices can impact the Partnership s financial results and financial position, either favorably or unfavorably.

Interest Rate Risk

The Partnership is exposed to market risk for changes in interest rates related to the bank credit facilities of the Partnership. The Partnership manages a portion of its interest rate exposures by utilizing interest rate swaps and similar arrangements, which allows the Partnership to effectively convert a portion of variable rate debt into fixed debt.

On January 6, 2005, the Partnership entered into a forward-starting interest swap with a notional amount of $300,000 in anticipation of the bonds issued on January 18, 2005. The purpose of entering into this transaction was to effectively hedge the underlying U.S. Treasury rate related to our anticipated issuance of $750,000 in principal amount of fixed rate debt. The settlement of the swap resulted in a loss of $363 which is recorded in accumulated other comprehensive income (loss). The loss will be amortized over the term of the bonds as interest expense.

The Partnership also entered into various forward starting interest swaps from February 2005 through May 2005, in anticipation of the issuance of an additional bond offering in the third or fourth fiscal quarter of 2005. Due to certain market conditions, the bond offering was postponed until July 29, 2005. Such agreements were designated as cash flow hedges of an anticipated transaction under SFAS 133. When the forward starting interest swaps settle and the anticipated bonds are issued, the gain or loss from the swap will be amortized over the term of the bonds through interest expense. Certain forward starting interest swaps settled during the year ended August 31, 2005 with a net $1,931 receipt from the counterparties. Due to the timing of entering into the forward starting interest swaps and the anticipated bond issuance, a gain of $2,434 was recorded as a reduction of interest expense in the year ended August 31, 2005. Forward starting interest swaps with a notional amount of $150,000 were entered into and outstanding as of August 31, 2005 and had a fair value of $2,156 which was recorded as unrealized losses in accumulated other comprehensive income (loss) and a component of price risk management liabilities in the consolidated balance sheet. Ineffectiveness related to the forward starting interest swaps during the year ended August 31, 2005 was a loss of $911 which was recorded as a component of interest expense. The outstanding interest rate swaps as of August 31, 2005 were entered into in anticipation of a bond offering to occur in the third quarter of fiscal year 2006.

ETC OLP also has an interest rate swap with a notional amount of $75,000 that matured in October 2005, and has a fair value of $151 and $539 as of August 31, 2005 and 2004, respectively. Under the terms of the swap agreement, the Partnership will pay a fixed rate of 2.76% and will receive three-month LIBOR with a quarterly settlement. The interest rate swap is not accounted for as a hedge but receives mark to market accounting. Accordingly, changes in the fair value are recorded as a component of interest expense in the consolidated statement of operations.

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The following represents gain (loss) on all derivative activity:

	Year Ended August 31, 2005	Year Ended August 31, 2004	Eleven Months Ended August 31, 2003
Unrealized gain recognized in earnings related to Partnership s derivative activity	$ 12,712	$ 2,919	$ 889
Realized gain (loss) included in revenue	$ 4,210	$ 22,314	$ (2,411)
Unrealized gain (loss) on interest rate swap	$ (81)	$ 266	$
Realized gain (loss) on interest rate swap included in interest expense	$ 1,953	$ (1,239)	$ (312)

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.

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.

12. PARTNERS CAPITAL:

Units

Common Units, Class D Units, Special Units, Class E Units and Class C Units represent limited partner interests in the Partnership that entitle the holders thereof to the rights and privileges specified in the Partnership Agreement, as amended. As of August 31, 2005, there were issued and outstanding 106,889,904 Common Units representing an aggregate 98% limited partner interest in the Partnership. There are also 8,853,832 Class E Units outstanding that are reported as treasury units and are entitled to receive distributions in accordance with their terms, and 1,000,000 Class C Units outstanding that are entitled only to participate in distributions that are attributable to the net amount received by the Partnership in connection with the SCANA litigation (defined in Note 10).

In connection with the Energy Transfer Transactions in January 2004, the Partnership issued 15,443,084 Class D Units and 7,485,030 Special Units to ETE (the terms of the Class D Units and Special Units are described in more detail below). On June 23, 2004, the Partnership held a special meeting for the Common Unitholders of record on May 17, 2004 for the purpose of approving a proposal to change the terms of the

Class D Units and the Special Units issued in connection with the Energy Transfer Transactions and to approve the Partnership s 2004 Unit Plan. At the meeting, the Common Unitholders approved (1) the change in terms and conversion of all 15,443,084 outstanding Class D Units into 15,443,084 Common Units, (2) the change in terms and conversion of all 7,485,030 outstanding Special Units into 7,485,030 Common Units upon the East Texas Pipeline becoming commercially operational, which occurred on June 21, 2004, and (3) the 2004 Unit Plan, which provides for awards of Common Units and other rights to the Partnership s employees, officers and directors.

No person is entitled to preemptive rights in respect of issuances of securities by the Partnership, except that ETP GP has the right to purchase sufficient partnership securities to maintain its general partner equity interest in the Partnership.

Common Units. The Partnership s Common Units are registered under the Securities Act of 1934 and are listed for trading on the New York Stock Exchange. Each holder of a Common Unit is entitled to one vote per unit on all matters presented to the Limited Partners for a vote. In addition, if at any time any person or group (other than the

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Partnership s General Partner and its affiliates) owns beneficially 20% or more of all Common Units, any Common Units owned by that person or group may not be voted on any matter and are not considered to be outstanding when sending notices of a meeting of Unitholders (unless otherwise required by law), calculating required votes, determining the presence of a quorum or for other similar purposes under the Partnership Agreement. The Common Units are entitled to distributions of Available Cash as described below under Quarterly Distributions of Available Cash.

On January 26, 2005, the Partnership placed $350,000 of Common Units in a private placement to institutional investors as part of the financing of the acquisition of HPL. In this private placement the Partnership issued 6,296,294 (post-split) unregistered Common Units for total consideration of $170,000 and the Partnership became obligated under a Units Purchase Agreement dated January 14, 2005 to issue an additional 6,666,666 (post-split) Common Units for total consideration of $180,000. These Common Units were issued pursuant to an effective shelf registration statement on March 18, 2005. The proceeds from these private placements were used to finance a portion of the HPL acquisition.

On January 27, 2005 the Partnership announced that the Board of Directors of the General Partner approved a two-for-one split for each class of the Partnership s limited partner units. The split entitled Unitholders of record at the close of business on February 28, 2005 to receive one additional Partnership unit for each Partnership unit owned on that date. The distribution of the additional units was made on March 15, 2005. The unit split required retroactive restatement of all historical per unit data in the consolidated financial statements for the quarter ended February 28, 2005. The effect of the split was to double the number of all outstanding Common Units and Class E Units and to reduce by half the minimum quarterly per unit distribution and the targeted distribution levels. All references to Common Units have been restated to reflect the effects of the two-for-one split.

In June 2005, the Partnership completed the sale of 1,640,000 Common Units to a group of executive managers of the Partnership, including the President, Vice-President and General Counsel, and Vice-President-Corporate Development. The units were sold at a price of $31.95 per Common Unit, which represented a 6% discount to the closing Common Unit price on June 17, 2005. The Partnership believes the price received is comparable to the price that it would have received from an unaffiliated purchaser in a large block equity transaction. The transaction was approved by a committee of independent directors of the General Partner.

On July 26, 2005, the Partnership completed the sale of 3,000,000 Common Units in a private sale to an institutional investor. The Common Units were issued pursuant to the Partnership s effective shelf registration statement and the proceeds of $105.6 million were used by the Partnership to retire a portion of the outstanding indebtedness on its revolving credit facility and to fund the Partnership s recently announced capital expansion projects.

On January 20, 2004, the Partnership completed the sale of 8,000,000 Common Units at a public offering price of $38.69. On January 27, 2004, the Underwriters for the equity offering exercised an over-allotment option and an additional 1,200,000 units were sold. Net proceeds from the Common Unit offering and the over-allotment option were $334,330 and were used to pay a portion of the consideration for the Energy Transfer Transactions, and for general partnership purposes, including, but not limited to, repayment of additional debt, working capital, and capital expenditures.

On June 30, 2004, the Partnership completed the sale of 4,500,000 Common Units at a public offering price of $39.20 per unit. On July 2, 2004 the Partnership issued 675,000 Common Units to the Underwriters upon their exercise of their over-allotment option at the offering price of $39.20 per unit. Net proceeds from the Common Units offering and the exercise of the over-allotment option were $193,799 and were used to repay a portion of the outstanding indebtedness incurred to fund the ET Fuel System acquisition and for general partnership purposes.

On March 18, 2004, the Partnership issued 22,240 Common Units, with a total value of $734 as final settlement of the purchase price for Heritage s acquisition of 50% of Bi State Propane that was not previously owned by Heritage.

Class C Units. The 1,000,000 Class C Units were issued to Heritage Holdings in August 2000 in conjunction with the transaction with U.S. Propane and the change of control of the Partnership s General Partner in conversion of that portion of Heritage Holding s Incentive Distribution Rights that entitled it to receive any distribution attributable to the net amount received by the Partnership in connection with the settlement, judgment, award or other final nonappealable resolution of specified litigation filed by the Partnership prior to the transaction with U.S. Propane, which is referred to as the SCANA litigation. The Class C Units have zero initial capital account balance and were distributed by Heritage Holdings to its former stockholders in connection with the transaction with U.S. Propane.

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All decisions of the Partnership s General Partner relating to the SCANA litigation are determined by a special litigation committee consisting of one or more independent directors of the Partnership s General Partner. As soon as practicable after the time that the Partnership or its affiliates receive any final cash or other payment as a result of the resolution of the SCANA litigation, the special litigation committee will determine the aggregate net amount of these proceeds distributable by the Partnership after deducting from the amounts received all costs and expenses incurred by the Partnership and its affiliates in connection with the SCANA litigation and any cash reserves necessary or appropriate to provide for operating expenditures.

Following this determination, the distributable proceeds will be deemed to be Available Cash under the Partnership Agreement and will be distributed as described below under Quarterly Distributions of Available Cash. The amount of distributable proceeds that would normally be distributed to holders of Incentive Distribution Rights will instead be distributed to the holders of the Class C Units, pro rata. The Partnership cannot predict whether it will receive any cash payments as a result of the SCANA litigation and, if so, when these distributions might be made to the Class C Unitholders.

The Class C Units do not have any rights to share in any of the Partnership s assets or distributions upon dissolution and liquidation of the Partnership, except to the extent that any such distributions consist of proceeds from the SCANA litigation to which the class C Unitholders would have otherwise been entitled. The Class C Units do not have the privilege of conversion into any other unit and do not have any voting rights except to the extent provided by law, in which case each Class C Unit will be entitled to one vote.

The amount of cash distributions to which the Incentive Distribution Rights are entitled was not increased by the creation of the Class C Units; rather, the Class C Units are a mechanism for dividing the Incentive Distribution Rights that Heritage Holdings and its former stockholders would have been entitled to.

Class D Units. The Class D Units were issued to ETE in connection with the Energy Transfer Transactions in January 2004 and generally had voting rights identical to the voting rights of the Common Units, and the Class D Units voted with the Common Units as a single class on each matter with respect to which the Common Units were entitled to vote. Each Class D Unit initially was entitled to receive 100% of the quarterly amount distributed on each Common Unit, for each quarter, provided that the Class D Units were subordinated to the Common Units with respect to the payment of the minimum quarterly distribution for such quarter (and any arrearage in the payment of the minimum quarterly distribution for all prior quarters). The Partnership was required, as promptly as practicable following the issuance of the Class D Units, to submit to a vote of the 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. Holders of the Class D Units were entitled to vote upon the proposal to change the terms of the Class D Units and the Special Units in the same proportion as the votes cast by the holders of the Common Units (other than the Common Units issued to La Grange Energy in connection with the Energy Transfer Transactions) with respect to this proposal. The 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.

Class E Units. In conjunction with the Partnership s purchase of the capital stock of Heritage Holdings, the 8,853,832 Common Units held by Heritage Holdings were converted into 8,853,832 Class E Units. The Class E Units generally do not have any voting rights but were entitled to vote on the proposals to make the Class D Units and Special Units convertible into Common Units. 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. In the event of the Partnership s termination and liquidation, the Class E Units will be allocated 1% of any gain upon liquidation and will be allocated any loss upon liquidation to the same extent as Common Units. After the allocation

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of such amounts, the Class E Units will be entitled to the balance in their capital accounts, as adjusted for such termination and liquidation. The terms of the Class E Units were determined in order to provide the Partnership with the opportunity to minimize the impact of its ownership of Heritage Holdings, including the $57,449 in deferred tax liabilities of Heritage Holdings that were included in the purchase of Heritage Holdings. The Class E Units are treated as treasury stock for accounting purposes because they are owned by the Partnership s wholly owned subsidiary, Heritage Holdings. Due to the ownership of the Class E Units by this corporate subsidiary, the payment of distributions on the Class E Units will result in annual tax payments by Heritage Holdings at corporate federal income tax rates, which tax payments will reduce the amount of cash that would otherwise be available for distribution to the Partnership as the owner of Heritage Holdings. Because distributions on the Class E Units will be available to the Partnership as the owner of Heritage Holdings, those funds will be available, after payment of taxes, for General Partnership purposes, including to satisfy working capital requirements, for the repayment of outstanding debt and to make distributions to the Unitholders. Because the Class E Units are not entitled to receive any allocation of Partnership income, gain, loss, deduction or credit that is attributable to our ownership of Heritage Holdings, such amounts will instead be allocated to the General Partner in accordance with its respective interest and the remainder to all Unitholders other than the holders of Class E Units pro rata. In the event that Partnership distributions exceed $1.41 per unit annually, all such amounts in excess thereof will be available for distribution to Unitholders other than the holders of Class E Units in proportion to their respective interests.

Special Units. The Special Units were issued to ETE on January 20, 2004 as consideration for the Bossier Pipeline in connection with the Energy Transfer Transaction. The Special Units generally did not have any voting rights but were entitled to vote on the proposal to change the terms of the Special Units in the same proportion as the votes cast by the holders of the Common Units (other than the Common Units issued to La Grange Energy in connection with the Energy Transfer Transaction) with respect to this proposal, and were not be entitled to share in partnership distributions. The Partnership was required, as promptly as practicable following the issuance of the Special Units, to submit to a vote of the Unitholders the approval of the conversion of the Special Units into Common Units in accordance with the terms of the Special Units. Following Unitholder approval at a special meeting of the Unitholders on June 23, 2004 and upon the Bossier Pipeline becoming commercially operational June 21, 2004, each Special Unit converted into one Common Unit on June 24, 2004 upon the request of the holder.

Incentive Distribution Rights. Incentive Distribution Rights represent the contractual right to receive an increasing 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. The General Partner owns all of the Incentive Distribution Rights, except that in conjunction with the August 2000 transaction with U.S. Propane, the Partnership issued 1,000,000 Class C Units to Heritage Holdings, its general partner at that time, in conversion of that portion of Heritage Holdings s Incentive Distribution Rights that entitled it to receive any distribution made by the Partnership of funds attributable to the net amount received in connection with the settlement, judgment, award or other final nonappealable resolution of the SCANA litigation.

Quarterly Distributions of Available Cash

The Partnership Agreement requires that the Partnership will distribute all of its Available Cash to its Unitholders and its General Partner within 45 days following the end of each fiscal quarter, subject to the payment of incentive distributions to the holders of Incentive Distribution Rights to the extent that certain target levels of cash distributions are achieved. The term Available Cash generally means, with respect to any fiscal quarter of the Partnership, all cash on hand at the end of such quarter, plus working capital borrowings after the end of the quarter, less reserves established by the General Partner in its sole discretion to provide for the proper conduct of the Partnership s business, to comply with applicable laws or any debt instrument or other agreement, or to provide funds for future distributions to partners with respect to any one or more of the next four quarters. Available Cash is more fully defined in the Partnership Agreement.

Distributions by the Partnership in an amount equal to 100% of Available Cash will generally be made 98% to the Common, Class D, and Class E Unitholders and 2% to the General Partner, subject to the payment of incentive distributions to the General Partner to the extent that certain target levels of cash distributions are achieved.

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On October 15, 2004, the Partnership paid a post-split quarterly distribution of $0.4125 per unit, or $1.65 per unit annually, to its Unitholders of record at the close of business on October 7, 2004. On January 14, 2005, the Partnership paid a post-split quarterly distribution of $0.4375 per ETP unit, or $1.75 per unit annually, to its Unitholders of record at the close of business on January 5, 2005. On March 16, 2005, the Partnership announced that it had completed its two-for-one split of its units. On April 14, 2005, the Partnership paid a post-split quarterly distribution of $0.4625 per unit, or $1.85 per unit annually, an increase of $0.025 per unit per quarter, or $0.10 annually. On July 15 2005, the Partnership paid a post-split distribution of $0.4875 per Common Unit, or $1.95 per unit annually, an increase of $0.10 per Common Unit on an annualized basis, to Unitholders of record at the close of business on July 8, 2005. In addition to these quarterly distributions, the General Partner of ETP received quarterly distributions for its general partner interest in ETP, and incentive distributions to the extent the quarterly distribution exceeded $0.275 per unit post-split. On September 2, 2005, the Partnership announced that it had declared a cash distribution for the fourth quarter ended August 31, 2005 of $0.50 per Common Unit, or $2.00 annually, an increase of $0.05 per Common Unit on an annualized basis. The distribution was paid on October 14, 2005 to Unitholders of record at the close of business on September 30, 2005. The total amount of distributions declared for the year ended August 31, 2005 on Common Units, Class E, General Partner interests and Incentive Distribution Rights totaled $190,440, $12,484, $4,926, and $38,455, respectively. All such distributions were made from Available Cash from the Partnership s Operating Surplus.

The Partnership makes distributions of available cash from operating surplus for any quarter in the following manner:

First, 98% to all Common and Class E 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 and Class E 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 distribution);

Third, 85% to all Common and Class E 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 distribution);

Fourth, 75% to all Common and Class E 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 distribution); and

Fifth, thereafter, 50% to all Common and Class E 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. Please read above for a discussion of the Class C Units and the percentage interests in distributions of the different classes of units.

13. RETIREMENT BENEFITS:

The Partnership also sponsors a defined contribution profit sharing and 401(k) savings plan, which covers virtually all employees subject to service period requirements. Profit sharing contributions are made to the plan at the discretion of the Board of Directors and are allocated to eligible employees as of the last day of the plan year. Employer matching contributions are calculated using a discretionary formula based on employee contributions. The Partnership made matching contributions of $4,106, $1,539, and $0 to the 401(k) savings plan for the years ended

August 31, 2005, 2004, and the eleven months ended August 31, 2003, respectively.

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14. RELATED PARTY TRANSACTIONS:

As of August 31, 2005 and 2004, accounts receivable from related companies was $4,479 and $34, respectively. Included in the receivable from related companies as of August 31, 2005 was a net receivable of $2,098 due from ETP GP comprised of its 2% contribution due for the July 2005 private placement of 3,000,000 Common Units. The remainder of the related party receivables as of August 31, 2005 of $2,831 and $34 as of August 31, 2004, is due from various related companies related to receivables in the normal course of business. Accounts payable to related companies as of August 31, 2005 and 2004, included $746 and $2,856, respectively, due to ETE related to the Energy Transfer Transactions. Accounts payable to related companies as of August 31, 2005 and 2004 also included approximately $321 and $1,420, respectively, payable to unconsolidated companies for purchases of natural gas and operating expenses incurred in the normal course of business.

As of August 31, 2005 the Partnership had a note payable of $1,992 related to its contribution in a cylinder exchange joint venture entered into July 2005 in which it owns a 50% interest. The note bears interest at an annual rate equal to the one month LIBOR rate plus 150 basis points, compounded monthly. The note is recorded as long-term affiliated payable on the Partnership s consolidated balance sheets. Included in accounts receivable from related companies as of August 31, 2005 is a receivable of $689 from this joint venture for administrative support services provided to and cash payments made on behalf of the joint venture by the Partnership.

ETC OLP secures compression services from third parties. Energy Transfer Technologies, Ltd. is one of the entities from which compression services are obtained. Energy Transfer Group, LLC is the general partner of Energy Transfer Technologies, Ltd. These entities are collectively referred to as the ETG Entities . The ETG Entities were not acquired by the Partnership in conjunction with the January 2004 Energy Transfer Transactions. The Partnership s Co-Chief Executive Officers have an indirect ownership and a director of the Partnership s General Partner has an ownership interest in the ETG Entities. In addition, two of the General Partner s directors serve on the Board of Directors of the ETG Entities. The terms of each arrangement to provide compression services are negotiated at an arm s length basis by management, and are reviewed and approved by the Audit Committee. During fiscal year 2005 and 2004, payments totaling $900 and $279, respectively, were made to the ETG Entities for compression services provided to and utilized in the Partnership s natural gas midstream operations. As of August 31, 2005 and 2004, accounts payable to ETG related to compressor leases were $102 and $7, respectively.

At August 31, 2005, the Partnership s natural gas midstream subsidiaries owned a 50% interest in South Texas Gas Gathering, a joint venture that owns an 80% interest in the Dorado System, a 61-mile gathering system located in South Texas. The other 50% equity interest in South Texas Gas Gathering is owned by an entity that includes one of the General Partner s directors. The Partnership is the operator of the Dorado System. At August 31, 2004, there was a balance of $248 owing to the Partnership by the entity that is owned in part by such director of the General Partner for services provided as operator, which was paid in full during the year ended August 31, 2005.

Prior to the Oasis Pipeline stock redemption and the contribution of ET Company I to ETC, ETC had purchases and sales of natural gas with Oasis Pipeline and ET Company I in the normal course of business. The following table summarizes these transactions:

	October 1, 2002 (Inception) Through December 21, 2002
Sales of natural gas to affiliated companies	$ 4,488
Purchases of natural gas from affiliated companies	$ 3,989
Transportation expenses	$ 922

Prior to the Energy Transfer Transactions, ET GP, LLC, the general partner of Holdings, had a general and administrative services contract to act as an advisor and provide certain general and administrative services to ETE and its affiliates. The general and administrative services that ET GP, LLC provides ETP under this contract include:

- General oversight and direction of engineering, accounting, legal and other professional and operational services required for the support, maintenance and operation of the assets used in the Midstream operations, and

- The administration, maintenance and compliance with contractual and regulatory requirements.

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In exchange for these services, ETE and its affiliates were required to pay ET GP, LLC a $500 annual fee payable quarterly and pro-rated for any portion of a calendar year. Pursuant to this contract, ETE and its affiliates were also required to reimburse ET GP, LLC for expenses associated with formation of ETE and its affiliates and are required to indemnify ET GP, LLC, its affiliates, officers and employees for liabilities associated with the actions of ET GP, LLC, its affiliates, officers, and employees. As a result of the reimbursement provision ETE charged ETC OLP $449 for expenses associated with its formation. For the eleven months ended August 31, 2003, ETC OLP was charged $375 under this contract. This general and administrative services contract was amended upon the closing of the Energy Transfer Transaction and the Partnership pays no portion of the fees associated with this contract. As of August 31, 2004, ETC OLP owed ETE $250 for expenses under the contract from October 1, 2003 through January 20, 2004. This amount was paid during fiscal year 2005.

In connection with the HPL acquisition, ETC OLP entered into a short-term loan agreement with ETE, whereby ETC OLP borrowed $174,624 to acquire the working inventory of natural gas stored in the Bammel storage facilities with interest based on the Eurodollar Rate plus 3.0% per annum. ETC OLP also incurred $3,109 in debt issuance costs associated with the loan agreement. The loan was paid in full during the year ended August 31, 2005 and $1,554 of unamortized debt issuance costs were written off and accounted for as loss on extinguishment of debt in the consolidated statements of operations for the year ended August 31, 2005. In addition, $1,506 of interest expense is included in the consolidated statement of operations for the year ended August 31, 2005 related to the loan with ETE.

15. SUMMARIZED CONDENSED CONSOLIDATING FINANCIAL STATEMENTS:

The Partnership s Revolving Credit Facility and Senior Notes are fully and unconditionally guaranteed by ETC OLP and all of the direct and indirect wholly-owned subsidiaries of ETC OLP (the Subsidiary Guarantors). HOLP and its direct and indirect subsidiaries and Heritage Holdings, Inc. do not guarantee the Partnership s Revolving Credit Facility and Senior Notes. The Subsidiary Guarantors, jointly and severally guarantee, on an unsecured, senior basis, the Partnership s obligations under the Partnership s Revolving Credit Facility and Senior Notes. The Subsidiary Guarantors, jointly and severally guarantee, on an unsecured, senior basis, the Partnership s obligations under ETP s Revolving Credit Facility and Senior Notes. Following are unaudited condensed consolidating financial information of the issuer (ETP), 100% Subsidiary Guarantors, the Non-Guarantor Subsidiaries and the Partnership on a consolidated basis. The presentations included in our quarterly reports on Form 10Q were not made in compliance with Rule 3-10 of Regulation S-X as the Partnership had no obligation to comply with the requirements of such Rule at that time. At the time of the quarterly presentations, the Partnership owned all of the interests of the Majority Subsidiary Guarantors other than a 2% limited partner interest in one entity, which 2% interest was owned by a non-affiliated third party. The condensed consolidating financial information for fiscal year 2005 has been modified from the previously filed quarterly reports. The condensed consolidating financial information presented herein complies with Rule 3-10 of Regulation S-X, is prepared on the equity method, and does not contain related financial statement disclosures that would be required with a complete set of financial statements presented in conformity with accounting principles generally accepted in the United States of America.

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATING BALANCE SHEET

As of August 31, 2005

(In thousands)

	Parent	100% Subsidiary Guarantors	Majority Owned Subsidiary Guarantors	Non-Guarantor Subsidiaries	Consolidation Adjustments	Consolidated
ASSETS						
CURRENT ASSETS:						
Cash and cash equivalents	$ 3,810	$	$ 38	$ 21,066	$	$ 24,914
Marketable securities				3,452		3,452
Accounts receivable, net of allowance for doubtful accounts		486,932	295,158	64,938		847,028
Accounts receivable from related companies	99,833	1,737,665	2,181,822	1,858	(4,016,699)	4,479
Inventories		8,209	217,116	77,568		302,893
Other current assets	917	247,696	18,813	7,828		275,254
Total current assets	104,560	2,480,502	2,712,947	176,710	(4,016,699)	1,458,020
PROPERTY, PLANT AND EQUIPMENT, net	9	1,124,293	813,867	502,396		2,440,565
INVESTMENT IN AFFILIATES	2,718,945	1,014,829	32,205	144,283	(3,872,909)	37,353
GOODWILL		23,736		300,283		324,019
INTANGIBLES AND OTHER ASSETS, net	13,057	286	1,160	97,656		112,159
LONG-TERM PRICE RISK MANAGEMENT ASSET		39,442	2,245			41,687
OTHER LONG-TERM ASSETS		11,250	1,716	137		13,103
Total assets	$ 2,836,571	$ 4,694,338	$ 3,564,140	$ 1,221,465	$ (7,889,608)	$ 4,426,906
LIABILITIES AND PARTNERS CAPITAL						
CURRENT LIABILITIES:						
Working capital facility	$	$	$	$ 17,026	$	$ 17,026
Accounts payable	2,181	483,819	280,771	52,004		818,775
Accounts payable to related companies	9,461	1,895,306	2,112,531	474	(4,016,699)	1,073
Other current liabilities	10,774	87,167	183,298	93,412		374,651
Current maturities of long-term debt				39,349		39,349
Total current liabilities	22,416	2,466,292	2,576,600	202,265	(4,016,699)	1,250,874
LONG-TERM DEBT, less current maturities	1,348,432			327,273		1,675,705
LONG-TERM AFFILIATED PAYABLE				2,005		2,005
LONG TERM PRICE RISK MANAGEMENT LIABILITIES		2,163	28,354			30,517
DEFERRED TAXES		52,854		58,331		111,185
MINORITY INTERESTS				1,825	15,319	17,144

OTHER NONCURRENT LIABILITIES		792	12,492			13,284
	1,370,848	2,522,101	2,617,446	591,699	(4,001,380)	3,100,714
COMMITMENTS AND CONTINGENCIES						
PARTNERS CAPITAL	1,465,723	2,172,237	946,694	629,766	(3,888,228)	1,326,192
Total liabilities and partners capital	$ 2,836,571	$ 4,694,338	$ 3,564,140	$ 1,221,465	$ (7,889,608)	$ 4,426,906

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATING BALANCE SHEET

As of August 31, 2004

(In thousands)

	Parent	100% Subsidiary Guarantors	Non-Guarantor Subsidiaries	Consolidation Adjustments	Consolidated
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$ 9,506	$ 52,054	$ 20,185	$	$ 81,745
Marketable securities			2,464		2,464
Accounts receivable, net of allowance for doubtful accounts		206,023	45,323		251,346
Accounts receivable from related companies	3,372	1,253	2,896	(7,487)	34
Other current assets	831	21,843	54,264		76,938
Assets held for sale, net		67,908			67,908
Total current assets	13,709	349,081	125,132	(7,487)	480,435
PROPERTY, PLANT AND EQUIPMENT, net		926,822	497,273		1,424,095
INVESTMENT IN AFFILIATES	989,833	7,593	155,553	(1,144,969)	8,010
GOODWILL		13,409	300,311		313,720
INTANGIBLES AND OTHER ASSETS, net		9,610	91,234		100,844
LONG-TERM AFFILIATED RECEIVABLE		95,000		(95,000)	
Total assets	$ 1,003,542	$ 1,401,515	$ 1,169,503	$ (1,247,456)	$ 2,327,104
LIABILITIES AND PARTNERS CAPITAL					
CURRENT LIABILITIES:					
Working capital facility	$	$	$ 14,550	$	$ 14,550
Accounts payable	716	197,897	37,018		235,631
Accounts payable to related companies	3,434	4,639	3,219	(7,016)	4,276
Liabilities held for sale		20,590			20,590
Other current liabilities	2,277	27,110	62,117	(471)	91,033
Current maturities of long-term debt			30,957		30,957
Total current liabilities	6,427	250,236	147,861	(7,487)	397,037
LONG-TERM DEBT, less current maturities		725,000	345,871		1,070,871
LONG-TERM AFFILIATED PAYABLE	95,000			(95,000)	
DEFERRED TAXES		54,436	55,460		109,896
MINORITY INTERESTS			1,475		1,475
OTHER NONCURRENT LIABILITIES		845			845
	101,427	1,030,517	550,667	(102,487)	1,580,124

COMMITMENTS AND CONTINGENCIES					
PARTNERS CAPITAL	902,115	370,998	618,836	(1,144,969)	746,980
Total liabilities and partners capital	$ 1,003,542	$ 1,401,515	$ 1,169,503	$ (1,247,456)	$ 2,327,104

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

For the year ended August 31, 2005

(In thousands)

	Parent	100% Subsidiary Guarantors	Majority Owned Subsidiary Guarantors	Non-Guarantor Subsidiaries	Consolidation Adjustments	Consolidated
REVENUES:						
Midstream and transportation and storage	$	$ 3,878,191	$ 2,314,781	$	$ (809,347)	$ 5,383,625
Propane				709,904		709,904
Other	116			75,153		75,269
Total revenue	116	3,878,191	2,314,781	785,057	(809,347)	6,168,798
COSTS AND EXPENSES:						
Cost of products sold		3,478,720	2,241,993	470,149	(809,347)	5,381,515
Operating expenses		97,332	38,669	183,553		319,554
Depreciation and amortization		27,767	12,555	52,621		92,943
Selling, general and administrative	13,361	24,635	12,071	12,668		62,735
Total costs and expenses	13,361	3,628,454	2,305,288	718,991	(809,347)	5,856,747
OPERATING INCOME (LOSS)	(13,245)	249,737	9,493	66,066		312,051
OTHER INCOME (EXPENSE):						
Interest expense	(44,475)	(18,422)	(160)	(31,427)	1,467	(93,017)
Equity in earnings (losses) of affiliates	407,679	9,205	(735)	39	(416,564)	(376)
Gain (loss) on disposal of assets		756		(1,086)		(330)
Loss on extinguishment of debt		(9,550)				(9,550)
Other, net	(501)	2,566	475	(442)	(1,467)	631
INCOME FROM CONTINUING OPERATIONS BEFORE MINORITY INTERESTS AND INCOME TAX EXPENSE	349,458	234,292	9,073	33,150	(416,564)	209,409
Minority interests				(542)	(189)	(731)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME EXPENSE	349,458	234,292	9,073	32,608	(416,753)	208,678
Income tax expense	(108)	(935)		(6,252)		(7,295)
INCOME FROM CONTINUING OPERATIONS	349,350	233,357	9,073	26,356	(416,753)	201,383
DISCONTINUED OPERATIONS:						

Income from discontinued operations		149,796		(1,829)		147,967
NET INCOME	$ 349,350	$ 383,153	$ 9,073	$ 24,527	$ (416,753)	$ 349,350

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

For the year ended August 31, 2004

(In thousands)

	Parent	100% Subsidiary Guarantors	Non-Guarantor Subsidiaries	Consolidation Adjustments	Consolidated
REVENUES:					
Midstream and transportation and storage	$	$ 1,966,803	$	$	$ 1,966,803
Propane			342,523		342,523
Other	20		37,611		37,631
Total revenue	20	1,966,803	380,134		2,346,957
COSTS AND EXPENSES:					
Cost of products sold		1,771,321	210,103		1,981,424
Operating expenses		43,112	104,262		147,374
Depreciation and amortization		17,063	31,536		48,599
Selling, general and administrative	4,047	18,760	7,664		30,471
Total costs and expenses	4,047	1,850,256	353,565		2,207,868
OPERATING INCOME (LOSS)	(4,027)	116,547	26,569		139,089
OTHER INCOME (EXPENSE):					
Interest expense	(2,464)	(20,547)	(20,676)	2,497	(41,190)
Equity in earnings (losses) of affiliates	105,884	499	(136)	(105,884)	363
Loss on disposal of assets		(7)	(999)		(1,006)
Other, net		3,086	(80)	(2,497)	509
INCOME FROM CONTINUING OPERATIONS BEFORE MINORITY INTERESTS AND INCOME TAX EXPENSE	99,393	99,578	4,678	(105,884)	97,765
Minority interests			(295)		(295)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME EXPENSE	99,393	99,578	4,383	(105,884)	97,470
Income tax expense	(241)	(1,716)	(2,524)		(4,481)
INCOME FROM CONTINUING OPERATIONS	99,152	97,862	1,859	(105,884)	92,989
DISCONTINUED OPERATIONS:					
Income from discontinued operations		6,163			6,163
NET INCOME	$ 99,152	$ 104,025	$ 1,859	$ (105,884)	$ 99,152

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

For the year ended August 31, 2005

(In thousands)

	Parent	100% Subsidiary Guarantor	Majority Owned Subsidiary Guarantor	Non-Guarantor Subsidiaries	Consolidation Adjustments	Consolidated
NET CASH FLOWS PROVIDED BY (USED IN) OPERATING ACTIVITIES	$ (41,651)	$ 131,610	$ 2,629	$ 76,830	$	$ 169,418
CASH FLOWS FROM INVESTING ACTIVITIES:						
Cash paid for acquisitions, net of cash acquired		(1,106,573)		(25,462)	191	(1,131,844)
Capital expenditures	(9)	(153,048)	(2,782)	(40,620)		(196,459)
Proceeds from sale of discontinued operations		191,606				191,606
Cash invested in affiliates	(1,628,195)	(51)		(2,304)	1,628,195	(2,355)
Proceeds from the sale of assets		997		4,306		5,303
Net cash used in investing activities	(1,628,204)	(1,067,069)	(2,782)	(64,080)	1,628,386	(1,133,749)
CASH FLOWS FROM FINANCING ACTIVITIES:						
Proceeds from borrowings	2,631,000	80,000		243,034		2,954,034
Principal payments on debt	(1,280,000)	(805,000)		(252,931)		(2,337,931)
Proceeds from borrowings from affiliates		174,624				174,624
Payments on borrowings from affiliates		(174,624)				(174,624)
Advances (to) from affiliates	(192,494)	192,494				
Capital contributions from General Partner	10,418	1,613,195		15,000	(1,628,195)	10,418
Net proceeds from issuance of Common Units	507,724					507,724
Distributions to parent		(194,175)		(32,577)	226,752	
Distributions from subsidiaries	211,147			15,605	(226,752)	
Debt issuance costs	(16,597)	(3,109)				(19,706)
Unit distributions	(207,039)					(207,039)
Net cash provided by (used in) financing activities	1,664,159	883,405		(11,869)	(1,628,195)	907,500
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(5,696)	(52,054)	(153)	881	191	(56,831)

CASH AND CASH EQUIVALENTS, beginning of period	9,506	52,054	191	20,185	(191)	81,745
CASH AND CASH EQUIVALENTS, end of period	$ 3,810	$	$ 38	$ 21,066	$	$ 24,914

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

For the year ended August 31, 2004

(In thousands)

	Parent	100% Subsidiary Guarantors	Non-Guarantor Subsidiaries	Consolidation Adjustments	Consolidated
NET CASH FLOWS PROVIDED BY (USED IN) OPERATING ACTIVITIES	$ (8,112)	$ 110,163	$ 60,644	$	$ 162,695
CASH FLOWS FROM INVESTING ACTIVITIES:					
Cash paid for acquisitions, net of cash acquired	(191,377)	(498,570)	(16,710)	24,822	(681,835)
Capital expenditures		(95,191)	(14,497)		(109,688)
Investments in unconsolidated subsidiaries	(372,982)	(250)	(72)	372,982	(322)
Proceeds from the sale of assets		105	1,003		1,108
Net cash used in investing activities	(564,359)	(593,906)	(30,276)	397,804	(790,737)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from borrowings	6,693	830,000	64,079	(6,693)	894,079
Principal payments on debt	(6,693)	(331,000)	(179,084)	6,693	(510,084)
Advances from (to) affiliates	95,000	(95,000)			
Capital contributions	22,231	292,982	80,000	(372,982)	22,231
Net proceeds from issuance of common units of subsidiary	528,129				528,129
Distributions to parent		(206,071)			(206,071)
Debt issuance costs		(8,236)			(8,236)
Unit distributions	(63,383)				(63,383)
Net cash provided by (used in) financing activities	581,977	482,675	(35,005)	(372,982)	656,665
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	9,506	(1,068)	(4,637)	24,822	28,623
CASH AND CASH EQUIVALENTS, beginning of period		53,122	24,822	(24,822)	53,122
CASH AND CASH EQUIVALENTS, end of period	$ 9,506	$ 52,054	$ 20,185	$	$ 81,745

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16. REPORTABLE SEGMENTS:

The Partnership s financial statements reflect four reportable segments:

ETC OLP:

- midstream operations
- transportation and storage operations

HOLP:

- retail propane operations
- wholesale propane operations, including the operations of MP Energy Partnership

Segments below the quantitative thresholds are classified as other . None of these segments have ever met any of the quantitative thresholds for determining reportable segments. As a result of the HPL acquisition, management has redefined the transportation operations to transportation and storage operations. Management has also combined the domestic wholesale propane and foreign wholesale propane segments into one segment for all periods presented in this report. The combined segment is referred to as the wholesale propane segment.

Midstream and transportation and storage segment revenues and expenses include intersegment and intrasegment transactions, which are generally based on transactions made at market-related rates. Consolidated revenues and expenses reflect the elimination of all material intercompany transactions. Certain overhead costs relating to a reportable segment have been allocated for purposes of calculating operating income.

The midstream operations focus on the gathering, compression, treating, processing, transportation and marketing of natural gas, primarily on or through the Southeast Texas System, and marketing operations related to our producer services business. Revenue is primarily generated by the volumes of natural gas gathered, compressed, treated, processed, transported, purchased and sold through the Partnership s pipelines (excluding the transportation pipelines) and gathering systems as well as the level of natural gas and NGL prices. The transportation and storage operations focus on transporting natural gas through the Partnership s Oasis Pipeline, ET Fuel System, East Texas Pipeline System, and HPL System. Revenue is typically generated from fees charged to customers to reserve firm capacity on or move gas through the pipeline on an interruptible basis. A monetary fee and/or fuel retention are also components of the fee structure. Excess fuel retained after consumption is typically valued at the first of the month published market prices and strategically sold when market prices are high. The transportation and storage operations also consist of the HPL System which generates its revenue primarily from the sale of natural gas to electric utilities, independent power plants, local distribution companies, industrial end-users, and other marketing companies. The use of the Bammel storage reservoir allows the Partnership to purchase physical natural gas and then sell financial contracts at a price sufficient to cover its carrying costs and provide a gross profit margin. The HPL System also transports natural gas for a variety of third party customers.

The Partnership s retail and wholesale propane segments sell products and services to retail and wholesale customers. Intersegment sales by the foreign wholesale segment to the domestic segment are priced in accordance with the partnership agreement of MP Energy Partnership. The Partnership manages its propane segments separately as each segment involves different distribution, sale, and marketing strategies. The Partnership evaluates the performance of its operating segments based on operating income exclusive of general partnership selling, general, and administrative expenses of $13,399 for the year ended August 31, 2005, $11,711 for the year ended August 31, 2004, and $0 for the eleven month period ended August 31, 2003

Investment in affiliates and equity in earnings (losses) of affiliates relate primarily to the Partnership s investments in Vantex Gas Pipeline Company and Vantex Energy Services, Ltd., and Mid-Texas which are included in our midstream segment and transportation and storage segments. The following table presents the unaudited financial information by segment for the following periods:

	Year Ended August 31, 2005	Year Ended August 31, 2004	Eleven Months Ended August 31, 2003
Volumes			
Midstream			
Natural gas MMBtu/d	1,694,573	1,026,773	505,725
NGLs bbls/d sold	12,707	6,920	9,332
Transportation and storage			
Natural gas MMBtu/d sold	1,361,729		
Natural gas MMBtu/d transported	3,495,434	1,090,710	921,352
NGLs Bbls/d sold	1,735		
Propane gallons (in thousands)			
Retail	406,334	226,209	
Wholesale	70,047	35,719	
Total gallons	476,381	261,928	

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	Year Ended August 31, 2005	Year Ended August 31, 2004	Eleven Months Ended August 31, 2003
Revenues:			
Midstream			
Unaffiliated	$ 3,246,772	$ 1,880,647	$ 898,377
Affiliated		16	709
Eliminations	(471,255)	(27,798)	(9,559)
Transportation and storage	2,608,108	113,938	41,500
Retail propane and related	709,473	349,344	
Wholesale propane	68,833	27,345	
Other	6,867	3,465	
Total	$ 6,168,798	$ 2,346,957	$ 931,027
Cost of sales:			
Midstream	$ 3,102,539	$ 1,787,849	$ 832,874
Eliminations	(471,255)	(27,798)	(9,559)
Transportation and storage	2,280,082	11,270	2,123
Retail propane	403,740	184,371	
Wholesale propane	64,667	24,871	
Other	1,742	861	
Total Cost of Sales	$ 5,381,515	$ 1,981,424	$ 825,438
Operating income (loss)			
Midstream	$ 99,133	$ 60,249	$ 37,906
Transportation and storage	160,098	56,299	17,689
Retail propane and other	66,902	27,209	
Wholesale propane	(1,291)	(812)	
Other	608	191	
Selling general and administrative expenses not allocated to segments	(13,399)	(4,047)	
Total	$ 312,051	$ 139,089	$ 55,595
Income from discontinued operations, net of income tax expense and minority interests:			
Midstream	$ 5,498	$ 6,163	$ 5,994
Gain (loss) on disposal of assets:			
Midstream	$ (34)	$ (6)	$
Transportation and storage	790	(1)	
Retail propane	(1,031)	(999)	
Wholesale propane	25		
Other	(80)		
Total	$ (330)	$ (1,006)	$
Minority interest expense:			
Transportation and storage	189		
Wholesale propane	542	$ 295	

Total	$ 731	$ 295	$
Depreciation and amortization:			
Midstream	$ 12,580	$ 9,637	$ 9,056
Transportation and storage	27,742	7,426	2,814
Retail propane	51,487	30,925	
Wholesale propane	754	432	
Other	380	179	
Total	$ 92,943	$ 48,599	$ 11,870
Interest expense			
Midstream	$ 15,491	$ 20,841	$ 11,924
Eliminations	(4,798)	(5,999)	(4,565)
Transportation and storage	7,889	5,704	5,097
Retail propane	31,428	20,644	
Other	43,007		
Total	$ 93,017	$ 41,190	$ 12,456
Earnings (losses) from equity investments			
Midstream	$ 320	$ 499	$ (149)
Transportation and storage	(735)		1,572
Other	39	(136)	
Total	$ (376)	$ 363	$ 1,423
Income tax expense			
Midstream	$ 32	$	$
Transportation and storage	903	1,716	4,432
Other	6,360	2,765	
Total	$ 7,295	$ 4,481	$ 4,432

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	August 31,	
	2005	2004
Total Assets:		
Midstream	$ 1,024,778	$ 519,542
Transportation and storage	2,289,992	785,754
Retail propane	1,016,313	956,021
Wholesale propane	34,755	22,601
Other	61,068	43,186
Total	$ 4,426,906	$ 2,327,104

	Year Ended August 31, 2005	Year Ended August 31, 2004
Additions to property, plant and equipment including acquisitions:		
Midstream	$ 92,774	$ 21,466
Transportation and storage	959,185	570,169
Retail propane	57,421	515,284
Wholesale propane	191	5,020
Other	1,610	3,229
Total	$ 1,111,181	$ 1,115,168

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17. QUARTERLY FINANCIAL DATA (UNAUDITED):

Summarized unaudited quarterly financial data is presented below. The sum of net income per limited partner unit by quarter may not equal the net income per limited partner unit for the year due to variations in the weighted average units outstanding used in computing such amounts and because of the reverse merger accounting that occurred with the Energy Transfer Transactions. Heritage s business is seasonal due to weather conditions in its service areas. Propane sales to residential and commercial customers are affected by winter heating season requirements, which generally results in higher operating revenues and net income 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. Sales to industrial and agricultural customers are much less weather sensitive. ETC OLP s business is also seasonal due to the recent acquisitions of the ET Fuel Systems and HPL. The Partnership expects margin related to HPL to be higher during the periods from November through March of each year and lower during the periods from April through October of each year due to the increased demand for natural gas during the cold weather. However, the Partnership can not 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 the Partnership operates, competitive factors in the energy industry, and other issues.

	Quarter Ended			
	November 30	February 28	May 31	August 31
Fiscal 2005:				
Revenues	$ 864,198	$ 1,439,844	$ 2,031,750	$ 1,833,006
Gross Profit	136,293	228,669	214,752	207,569
Operating income	49,052	117,630	78,868	66,501
Net income	30,610	87,601	189,510	41,629
Basic net income per limited partner unit	$ 0.27	$ 0.77	$ 1.13	$ 0.40
Diluted net income per limited partner unit	$ 0.27	$ 0.77	$ 1.12	$ 0.40

	Quarter Ended			
	(Energy Transfer Company) November 30	February 29	May 31	August 31
Fiscal 2004:				
Revenues	$ 390,885	$ 602,852	$ 597,919	$ 755,301
Gross Profit	33,682	101,168	110,959	119,724
Operating income	19,436	57,721	34,489	27,443
Net income	15,694	49,238	21,330	12,890
Basic and diluted net income per limited partner unit	$ 1.16	$ 1.08	$ 0.32	$ 0.11

Certain amounts from previously reported quarters have been reclassified to conform with current presentation primarily due to the sale of the Elk City System (see Note 5, Discontinued Operations). The gain on the sale of the Elk City operations of $142,469, net of income tax expense of $1,829, occurred in the third quarter of fiscal year 2005. These reclassifications have no impact on net income or total partners capital. The basic and diluted net income per limited partner unit numbers above reflect the effect of the two-for-one split completed on March 15, 2005.

The amount of basic and diluted earnings per limited partner unit for the quarter ended February 28, 2005 differ from the amounts previously reported of $0.82 and $0.82, respectively, and for the quarter ended May 31, 2005 of $1.71 and $1.70, respectively. The difference relates to the Partnership s application of certain provisions of EITF 03-6. The dilutive effect of EITF 03-6 on basic and diluted net income per limited partner unit was $0.77 and $0.77 for the quarter ended February 28, 2005, respectively, and $1.13 and $1.12 for the quarter ended May 31, 2005, respectively. There was no effect on basic or diluted net income per limited partner unit for any other quarter in each of the two years ended August 31, 2005, because the Partnership s aggregate distributions exceed aggregate earnings for the period.

18. SUBSEQUENT EVENTS (unaudited):

On November 10, 2005 the Partnership purchased the 2% limited partner interest in HPL, that it did not already own, from AEP for $16,560 in cash. As a result, HPL became a wholly owned subsidiary of ETC OLP. The Partnership also reached a settlement agreement with AEP related to the inventory and working capital matters associated with the HPL acquisition discussed in Note 6. The terms of the agreement were not material in relation to the Partnership s financial position, results of operations or cash flows.

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INDEX TO EXHIBITS

The exhibits listed on the following Exhibit Index are filed as part of this report. Exhibits required by Item 601 of Regulation S-K, but which are not listed below, are not applicable.

	Exhibit Number	Description
(1)	3.1	Agreement of Limited Partnership of Heritage Propane Partners, L.P.
(8)	3.1.1	Amendment No. 1 to Amended and Restated Agreement of Limited Partnership of Heritage Propane Partners, L.P.
(13)	3.1.2	Amendment No. 2 to Amended and Restated Agreement of Limited Partnership of Heritage Propane Partners, L.P.
(16)	3.1.3	Amendment No. 3 to Amended and Restated Agreement of Limited Partnership of Heritage Propane Partners, L.P.
(16)	3.1.4	Amendment No. 4 to Amended and Restated Agreement of Limited Partnership of Heritage Propane Partners, L.P.
(21)	3.1.5	Amendment No. 5 to Amended and Restated Agreement of Limited Partnership of Heritage Propane Partners, L.P.
(21)	3.1.6	Amendment No. 6 to Amended and Restated Agreement of Limited Partnership of Heritage Propane Partners, L.P.
(34)	3.1.7	Amendment No. 7 to Amended and Restated Agreement of Limited Partnership of Heritage Propane Partners, L.P.
(1)	3.2	Agreement of Limited Partnership of Heritage Operating, L.P.
(10)	3.2.1	Amendment No. 1 to Amended and Restated Agreement of Limited Partnership of Heritage Operating, L.P.
(16)	3.2.2	Amendment No. 2 to Amended and Restated Agreement of Limited Partnership of Heritage Operating, L.P.
(21)	3.2.3	Amendment No. 3 to Amended and Restated Agreement of Limited Partnership of Heritage Operating, L.P.
(21)	3.3	Amended Certificate of Limited Partnership of Energy Transfer Partners, L.P.
(15)	3.4	Amended Certificate of Limited Partnership of Heritage Operating, L.P.
(17)	4.1	Registration Rights Agreement for Limited Partner Interests of Heritage Propane Partners, L.P.
(21)	4.2	Unitholder Rights Agreement dated January 20, 2004 among Heritage Propane Partners, L.P., Heritage Holdings, Inc., TAAP LP and La Grange Energy, L.P.
(27)	4.3	Indenture dated January 18, 2005 among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and Wachovia Bank, National Association , as trustee.
(28)	4.4	First Supplemental Indenture dated January 18, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee.

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	Exhibit Number	Description
(36)	4.5	Second Supplemental Indenture dated as of February 24, 2005 to Indenture dated as of January 18, 2005.
(37)	4.6	Notation of Guaranty.
(29)	4.7	Registration Rights Agreement, dated January 18, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and the initial purchasers party thereto.
(38)	4.8	Joinder to Registration Rights Agreement, dated February 24, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors and Wachovia Bank, National Association as trustee.
(40)	4.9	Third Supplemental Indenture, dated July 29, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee.
(41)	4.10	Registration Rights Agreement, dated July 29, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and the initial purchasers thereto.
(1)	10.2	Form of Note Purchase Agreement (June 25, 1996).
(2)	10.2.1	Amendment of Note Purchase Agreement (June 25, 1996) dated as of July 25, 1996.
(3)	10.2.2	Amendment of Note Purchase Agreement (June 25, 1996) dated as of March 11, 1997.
(5)	10.2.3	Amendment of Note Purchase Agreement (June 25, 1996) dated as of October 15, 1998.
(6)	10.2.4	Second Amendment Agreement dated September 1, 1999 to June 25, 1996 Note Purchase Agreement.
(9)	10.2.5	Third Amendment Agreement dated May 31, 2000 to June 25, 1996 Note Purchase Agreement and November 19, 1997 Note Purchase Agreement.
(8)	10.2.6	Fourth Amendment Agreement dated August 10, 2000 to June 25, 1996 Note Purchase Agreement and November 19, 1997 Note Purchase Agreement.
(11)	10.2.7	Fifth Amendment Agreement dated as of December 28, 2000 to June 25, 1996 Note Purchase Agreement, November 19, 1997 Note Purchase Agreement and August 10, 2000 Note Purchase Agreement.
(21)	10.2.8	Sixth Amendment Agreement dated as of December 28, 2000 to June 25, 1996 Note Purchase Agreement, November 19, 1997 Note Purchase Agreement and August 10, 2000 Note Purchase Agreement.
(1)	10.3	Form of Contribution, Conveyance and Assumption Agreement among Heritage Holdings, Inc., Heritage Propane Partners, L.P. and Heritage Operating, L.P.
(15) **	10.6.3	Second Amended and Restated Restricted Unit Plan dated as of February 4, 2002.
(25)	10.6.4	2004 Unit Plan.
(26)	10.6.5	Form of Grant Agreement.
(4)	10.16	Note Purchase Agreement dated as of November 19, 1997.

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	Exhibit Number	Description
(5)	10.16.1	Amendment dated October 15, 1998 to November 19, 1997 Note Purchase Agreement.
(6)	10.16.2	Second Amendment Agreement dated September 1, 1999 to November 19, 1997 Note Purchase Agreement and June 25, 1996 Note Purchase Agreement.
(7)	10.16.3	Third Amendment Agreement dated May 31, 2000 to November 19, 1997 Note Purchase Agreement and June 25, 1996 Note Purchase Agreement.
(8)	10.16.4	Fourth Amendment Agreement dated August 10, 2000 to November 19, 1997 Note Purchase Agreement and June 25, 1996 Note Purchase Agreement.
(11)	10.16.5	Fifth Amendment Agreement dated as of December 28, 2000 to June 25, 1996 Note Purchase Agreement, November 19, 1997 Note Purchase Agreement and August 10, 2000 Note Purchase Agreement.
(22)	10.16.6	Sixth Amendment Agreement dated as of November 18, 2003 to June 25, 1996 Note Purchase Agreement, November 19, 1997 Note Purchase Agreement and August 10, 2000 Note Purchase Agreement.
(8)	10.17	Contribution Agreement dated June 15, 2000 among U.S. Propane, L.P., Heritage Operating, L.P. and Heritage Propane Partners, L.P.
(8)	10.17.1	Amendment dated August 10, 2000 to June 15, 2000 Contribution Agreement
(8)	10.18	Subscription Agreement dated June 15, 2000 between Heritage Propane Partners, L.P. and individual investors
(8)	10.18.1	Amendment dated August 10, 2000 to June 15, 2000 Subscription Agreement
(13)	10.18.2	Amendment Agreement dated January 3, 2001 to the June 15, 2000 Subscription Agreement.
(14)	10.18.3	Amendment Agreement dated October 5, 2001 to the June 15, 2000 Subscription Agreement.
(8)	10.19	Note Purchase Agreement dated as of August 10, 2000.
(11)	10.19.1	Fifth Amendment Agreement dated as of December 28, 2000 to June 25, 1996 Note Purchase Agreement, November 19, 1997 Note Purchase Agreement and August 10, 2000 Note Purchase Agreement.
(12)	10.19.2	First Supplemental Note Purchase Agreement dated as of May 24, 2001 to the August 10, 2000 Note Purchase Agreement.
(22)	10.19.3	Sixth Amendment Agreement dated as of December 28, 2000 to June 25, 1996 Note Purchase Agreement, November 19, 1997 Note Purchase Agreement and August 10, 2000 Note Purchase Agreement.
(15)	10.26	Assignment, Conveyance and Assumption Agreement between U.S. Propane, L.P. and Heritage Holdings, Inc., as the former General Partner of Heritage Propane Partners, L.P. dated as of February 4, 2002

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	Exhibit Number	Description
(15)	10.27	Assignment, Conveyance and Assumption Agreement between U.S. Propane, L.P. and Heritage Holdings, Inc., as the former General Partner of Heritage Operating, L.P., dated as of February 4, 2002
(18)	10.28	Assignment for Contribution of Assets in Exchange for Partnership Interest dated December 9, 2002 among V-1 Oil Co., the shareholders of V-1 Oil Co., Heritage Propane Partners, L.P. and Heritage Operating, L.P.
(19)	10.30	Acquisition Agreement dated November 6, 2003 among the owners of U.S. Propane, L.P. and U.S. Propane, L.L.C., and La Grange Energy, L.P.
(19)	10.31	Contribution Agreement dated November 6, 2003 among La Grange Energy, L.P., and Heritage Propane Partners, L.P. and U.S. Propane, L.P.
(20)	10.31.1	Amendment No. 1 dated December 7, 2003 to Contribution Agreement dated November 6, 2003 among La Grange Energy, L.P. and Heritage Propane Partners, L.P. and U.S. Propane, L.P.
(19)	10.32	Stock Purchase Agreement dated November 6, 2003 among the owners of Heritage Holdings, Inc. and Heritage Propane Partners, L.P.
(23)	10.35	Purchase and Sale Agreement between TXU Fuel Company and Energy Transfer Partners, L.P. dated April 25, 2004.
(23)	10.35.1	First Amendment to Purchase and Sale Agreement and Closing Agreement between TXU Fuel Company and Energy Transfer Partners, L.P. dated June 1, 2004.
(24)	10.36	Third Amended and Restated Credit Agreement amount Heritage Operating L.P. and the Banks dated March 31, 2004.
(30)	10.40	Credit Agreement, dated January 18, 2005, among Energy Transfer Partners, L.P., Wachovia Bank, National Association, as administrative agent, LC issuer and swingline lender, Fleet National Bank, as syndication agent, BNP Paribas and The Royal Bank of Scotland PLC, as co- documentation agents, and other lenders party thereto.
(39)	10.40.1	First Amendment to Credit Agreement dated January 18, 2005, among Energy Transfer Partners, L.P., Wachovia Bank, National Association, as administrative agent, LC issuer and swingline lender, Fleet National Bank, as syndication agent, BNP Paribas and The Royal Bank of Scotland PLC, as co-documentation agents, and other lenders party thereto.
(31)	10.41	Guaranty, dated January 18, 2005, by the Subsidiary Guarantors in favor of Wachovia Bank, National Association, as the administrative agent for the lenders.
(39)	10.41.1	Guaranty Supplement dated February 24, 2005.
(32)	10.42	Purchase and Sale Agreement, dated January 26, 2005, among HPL Storage, LP and AEP Energy Services Gas Holding Company II, L.L.C., as Sellers and La Grange Acquisition, L.P., as Buyer.
(33)	10.43	Cushion Gas Litigation Agreement, dated January 26, 2005, by and among AEP Energy Services Gas Holding Company II, L.L.C. and HPL Storage LP, as Sellers, and La Grange Acquisition, L.P., as Buyer, and AEP Asset Holdings LP, AEP Leaseco LP, Houston Pipe Line Company, LP and HPL Resources Company LP, as Companies.
(35)	10.44	Loan Agreement, dated as of January 26, 2005 between La Grange Acquisition, L.P., as Borrower, and La Grange Energy, L.P., as Lender.
(*)	10.45	Summary of Director Compensation

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	Exhibit Number	Description
(*)	21.1	List of Subsidiaries.
(*)	23.1	Consent of Grant Thornton LLP
(*)	31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
(*)	31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
(*)	32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
(*)	32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
(*)	99.1	Financial Statements of U.S. Propane, L.P. as of August 31, 2005.
(*)	99.2	Financial Statements of U.S. Propane, L.L.C. as of August 31, 2005.

(*) Filed herewith.
(**) Denotes a management contract or compensatory plan or arrangement.
(1) Incorporated by reference to the same numbered Exhibit to Registrant s Registration Statement of Form S-1, File No. 333-04018, filed with the Commission on June 21, 1996.
(2) Incorporated by reference to the same numbered Exhibit to Registrant s Form 10-Q for the quarter ended November 30, 1996.
(3) Incorporated by reference to the same numbered Exhibit to Registrant s Form 10-Q for the quarter ended February 28, 1997.
(4) Incorporated by reference to the same numbered Exhibit to Registrant s Form 10-Q for the quarter ended May 31, 1998.
(5) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-K for the year ended August 31, 1998.
(6) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-K for the year ended August 31, 1999.
(7) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended May 31, 2000.
(8) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 8-K dated August 23, 2000.
(9) Filed as Exhibit 10.16.3.
(10) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-K for the year ended August 31, 2000.
(11) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended February 28, 2001.

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(12) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended May 31, 2001.
(13) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-K for the year ended August 31, 2001.
(14) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended November 30, 2001.
(15) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended February 28, 2002.
(16) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended May 31, 2002.
(17) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 8-K dated February 4, 2002.
(18) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 8-K dated January 6, 2003.
(19) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended May 31, 2003.
(20) Incorporated by reference to the same numbered Exhibit to Registrant s Form 10-Q for the quarter ended November 30, 2003).
(21) Incorporated by reference as the same numbered exhibit to the Registrant s Form 10-Q for the quarter ended February 29, 2004.
(22) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended February 29, 2004.
(23) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 8-K filed June 14, 2004.
(24) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended May 31, 2004.
(25) Incorporated by reference to Annex A of the Registrant s Schedule 14A Proxy Statement filed May 18, 2004.
(26) Incorporated by reference to Exhibit 10.1 to the Registrant s Form 8-K filed November 1, 2004.
(27) Incorporated by reference to Exhibit 4.1 to the Registrant s Form 8-K filed January 19, 2005.
(28) Incorporated by reference to Exhibit 4.2 to the Registrant s Form 8-K filed January 19, 2005.
(29) Incorporated by reference to Exhibit 4.3 to the Registrant s Form 8-K filed January 19, 2005
(30) Incorporated by reference to Exhibit 10.1 to the Registrant s Form 8-K filed January 19, 2005
(31) Incorporated by reference to Exhibit 10.2 to the Registrant s Form 8-K filed January 19, 2005
(32) Incorporated by reference to Exhibit 10.1 to the Registrant s Form 8-K filed February 1, 2005
(33) Incorporated by reference to Exhibit 10.2 to the Registrant s Form 8-K filed February 1, 2005
(34) Incorporated by reference to Exhibit 3.1.7 to the Registrant s Form 8-K filed March 16, 2005.

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(35) Incorporated by reference to Exhibit 10.3 to the Registrant s Form 8-K filed March 17, 2005.
(36) Incorporated by reference to Exhibit 10.45 to the Registrant s Form 10-Q for the quarter ended February 28, 2005.
(37) Incorporated by reference to Exhibit 10.46 to the Registrant s Form 10-Q for the quarter ended February 28, 2005.
(38) Incorporated by reference to Exhibit 10.39.1 to the Registrant s Form 10-Q for the quarter ended February 28, 2005.
(39) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended February 28, 2005.
(40) Incorporated by reference to Exhibit 4.1 to the Registrant s Form 8-K filed August 2, 2005.
(41) Incorporated by reference to Exhibit 4.2 to the Registrant s Form 8-K filed August 2, 2005.