ENERGY TRANSFER PARTNERS LP
Form 10-K
November 15, 2004

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

x **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended August 31, 2004

OR

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Transition Period from _________ to _________

Commission file number 1-11727

ENERGY TRANSFER PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

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

2838 Woodside Street, Dallas, Texas 75204
(Address of principal executive offices and zip code)

(918) 492-7272
(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 o

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act).

Yes x No o

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

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The aggregate market value as of February 29, 2004, 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 $880,100,000. 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 12, 2004, the registrant had units outstanding as follows:

Energy Transfer Partners, L.P.	44,639,306 Common Units

Documents Incorporated by Reference: None

ENERGY TRANSFER PARTNERS, L.P.

2004 FORM 10-K ANNUAL REPORT

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PART I

ITEM 1. BUSINESS

Overview

Energy Transfer Partners, L.P is one of the ten largest publicly traded master limited partnerships in the United States. We are engaged in the natural gas midstream and transportation business through our operating subsidiary, La Grange Acquisition, L.P. (ETC OLP), and are a retail marketer of propane in the United States through our operating subsidiary, Heritage Operating, L.P (HOLP). We are a publicly traded Delaware limited partnership formed in conjunction with an initial public offering as Heritage Propane Partners, L.P. in June of 1996. Following the completion of a series of transactions in January 2004, we combined the retail propane operations of Heritage Propane Partners, L.P. with the natural gas midstream and transportation operations of ETC OLP. In March 2004, we changed our name to Energy Transfer Partners, L.P. References to we, us, our, or the Partnership are intended to mean Energy Transfer Partners, L.P., our operating limited partnerships and subsidiaries. The business of Heritage Propane Partners, L.P. and Heritage Operating, L.P. prior to the transaction in January 2004, is referred to as Predecessor Heritage or Heritage.

ETC OLP s operations are divided into two business segments, consisting of the midstream segment and the transportation segment. We own and operate approximately 7,750 miles of natural gas gathering and transportation pipelines, four natural gas processing plants connected to our gathering systems, thirteen natural gas treating facilities and two natural gas storage facilities. Our midstream segment focuses on the gathering, compression, treating, blending, processing and marketing of natural gas and is currently concentrated in the Austin Chalk trend of southeast Texas, the Anadarko Basin of western Oklahoma and the Permian Basin of west Texas. Our transportation segment focuses on the transportation of natural gas mainly through the Oasis Pipeline, the Bossier Pipeline, and the ET Fuel System, which are described below.

Through HOLP, we are the fourth largest retail propane marketer in the United States, serving more than 650,000 customers from 310 customer service locations in 32 states. Our propane operations extend from coast to coast, with concentrations in the western, upper midwestern, northeastern and southeastern regions of the United States. Volumes of propane sold to retail customers have increased steadily from 63.2 million gallons for the fiscal year ended August 31, 1992, to 397.9 million gallons for the fiscal year ended August 31, 2004.

See Note 13 Reportable Segments to the Consolidated Financial Statements beginning on page F-1 of this report for financial information about these operating segments.

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

Energy Transfer Transactions

On January 20, 2004, Heritage and La Grange Energy, L.P. (La Grange Energy) completed a series of transactions whereby La Grange Energy 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 La Grange Energy 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 La Grange Energy and an affiliate of La Grange Energy contributed an office building to ETC OLP. La Grange Energy also received 3,742,515 Special Units as consideration for the project it had in progress to construct the Bossier Pipeline. The Special Units converted to Common Units upon the Bossier Pipeline becoming commercially operational and such conversion being approved by Energy Transfer Partners, L.P. s Unitholders. The Bossier 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, La Grange Energy obtained control of Heritage by acquiring all of the interests in U.S. Propane, L.P., (U.S. Propane) the General Partner of Heritage, and U.S. Propane s general partner, 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, U.S. Propane L.P. 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 and Expansion

TUFCO Acquisition. On June 2, 2004, we announced the closing of the acquisition of the midstream natural gas assets of TXU Fuel Company, a gas transportation subsidiary of TXU Corp., which we refer to as the TUFCO acquisition, for approximately $500.0 million in cash, subject to post-closing adjustments. The former TUFCO System, which we refer to as the ET Fuel System, serves some of the most active drilling areas in the United States. The ET Fuel System 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 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. The ET Fuel System has total system throughput capacity of approximately 1.3 Bcf/d of natural gas and total working storage capacity of 14.0 Bcf of natural gas. The ET Fuel System had been operated by TUFCO 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 refer to as TXU. As part of this acquisition, we entered into an eight-year transportation agreement with TXU Portfolio Management Company, LP, a subsidiary of TXU, which we refer to as TXU Shipper, to transport a minimum of 115.6 MMbtu per year, subject to adjustments, of gas to TXU s electric generating power plants and 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. We also acquired existing transportation contracts for the ET Fuel System with other natural gas producers, natural gas marketing companies, industrial end-users and other customers, which accounted for approximately 30% of the total revenue of the ET Fuel System for the year ended December 31, 2003.

Bossier Pipeline Expansion. In June 2004, we completed our Bossier Pipeline expansion, which consisted of 78 miles of pipeline that connected certain third party and ETC OLP-owned treating facilities to our Southeast Texas assets. The Bossier Pipeline expansion provides initial capacity of 500 MMcf/d that can be increased to 1.0 Bcf/d. The pipeline provides producers in North Central and East Texas access to the Katy Hub. We currently have contracted under long-term agreements over 400 MMcf/d of pipeline capacity on the Bossier Pipeline.

Devon Acquisition. On November 1, 2004 we announced the closing of the acquisition of certain midstream natural gas assets of Devon Energy Corporation (Devon) for approximately $64.6 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.

Fort Worth Basin Expansion. We are currently constructing a 54-mile pipeline in the Fort Worth Basin that will connect certain pipelines in North Texas. We expect that this expansion will provide us with 400 MMcf/d of pipeline capacity and is anticipated to be completed by March 2005. The expansion is estimated to cost approximately $53.0 million, which we expect to finance from internally generated funds.

Recent Propane Acquisitions. In April 2004, we announced the acquisition of the assets of Edwards Propane of Marshville, North Carolina. Edwards Propane serves approximately 9,000 customers in and around the Marshville area. In July 2004, we announced the acquisition of the assets of Custer Gas Service, Inc., in Custer, South Dakota. Custer Gas serves approximately 1,800 customers in the Custer area. We recently announced two additional propane acquisitions made during the first quarter of fiscal year 2005. The acquisition of the assets of Boland Energy in September 2004 and of Trenton Propane in October 2004, added customer bases purchasing approximately 4.8 million gallons annually in the rural area west of St. Louis, Missouri and approximately 2.0 million gallons annually in the area north of Dallas, Texas, respectively.

Other Developments

Distribution Increases. On April 14, 2004, we paid a quarterly cash distribution of $0.70 per Common Unit (an annualized rate of $2.80 per Common Unit) on our outstanding Common Units for the second quarter of fiscal year 2004. The $0.70 per Common Unit quarterly distribution represented an increase of $0.05 per Common Unit (an annualized increase of $0.20 per unit) over the distribution paid for the first quarter of fiscal 2004. In connection with the completion of our acquisition of the ET Fuel System, our Board of Directors approved an increase in the quarterly cash distribution from $0.70 to $0.75 per Common Unit, which resulted in an annualized rate of $3.00 per Common Unit with respect to the quarter ended May 31, 2004. On September 20, 2004, we announced our twelfth increase in our quarterly cash distribution, a 10% increase to $0.825 per Common Unit (an annualized rate of $3.30 per unit) on our outstanding Common Units with respect to the quarter ended August 31, 2004.

Amendment to Midstream Credit Facilities. On June 1, 2004, we amended our credit facilities secured by the assets of ETC OLP, which we refer to as our Midstream Facilities, to increase the available borrowing capacity. The borrowing capacity under our Term Loan Facility was increased to $725.0 million from $325.0 million and the borrowing capacity under our Revolving Credit Facility was increased to $225.0 million from $175.0 million. Our Midstream Facilities were also amended to increase our leverage ratio to 4.75 to 1.0 during the 365-day period following the funding of the purchase price of the ET Fuel System and to 4.00 to 1.00 during any period other than the 365-day period following the funding of the purchase price of the ET Fuel System. Leverage ratio means, as of any date of determination, the ratio of (a) consolidated funded indebtedness to (b) consolidated EBITDA (terms as defined in the bank credit facilities) for the four fiscal quarter period most recently ended prior to the date of determination for which financial statements are available. Effective August 31, 2004 we amended the Credit Agreement relating to our Midstream Facilities to ease the administration of our reporting obligations thereunder and to correct other inconsistencies.

Special Unitholder Meeting. On June 23, 2004, we held a special meeting for our 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 our 2004 Unit Plan. At the meeting, our Common Unitholders approved (1) the change in terms and conversion of all 7,721,542 outstanding Class D Units into 7,721,542 Common Units, (2) the change in terms and conversion of all 3,742,515 outstanding Special Units into 3,742,515 Common Units upon the Bossier Pipeline becoming commercially operational, which occurred on June 21, 2004, and (3) our 2004 Unit Plan, which provides for awards of Common Units and other rights to our employees, officers and directors.

Secondary Equity Offering. On June 30, 2004, we the completed of the sale of 4.5 million Common Units at a public offering price of $39.20 per unit. Net proceeds from the Common Unit offering of approximately $169.0 million were used to repay a portion of the outstanding indebtedness incurred to fund the ET Fuel System acquisition and for general partnership purposes. On July 2, 2004 we 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.

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Energy Transfer Company

The following table set forth below contains certain information regarding our midstream and transportation assets.

					Approximate Current	
Asset	Type	Length (Miles)	Approximate Wells Connected	Throughput Capacity MMcf/d)	Average Throughput (MMcf/d)	Utilization of Capacity (%)
Midstream						
Southeast Texas System	Gathering pipelines	2,379	1,050	720	250	35%
	Processing facility			240	120	50%
	6 Treating facilities			490	163	33%
Southeast Texas System Devon Assets (c)	Gathering pipelines	1,800	1,000	525	120	23%
	Processing facility			80	25	31%
	4 Treating facilities			250	70	28%
	Stabilizer plant					
	Fractionator plant					
Elk City System	Gathering pipelines	318	300	410	250	61%
	Processing facility			130	120	92%
	2 Treating facilities			275	245	89%
Small Systems (a) (d)	Gathering pipelines	525	138	556	140	25%
	Processing facility			20	20	100%
	1 Treating facility			30	8	27%
Transportation						
Oasis Pipeline	Transportation pipeline	583		1,200	1,180	98%
ET Fuel System (b)	Transportation pipeline	2,000		1,300	730	56%
Bossier Pipeline (c) (East Texas Pipeline)	Transportation pipeline	132		500	300	60%

			Working Storage Capacity

ET Fuel System (b)	Bethel Storage Facility	7.5 Bcf
	Bryson Storage Facility	6.5 Bcf

(a) We own interests in various midstream assets located in Texas and Louisiana. Amounts represent 100% and not just our interests.

(b) ET Fuel System was acquired in June 2004.

(c) Bossier Pipeline became operational in June 2004. Average throughput is based on date the pipeline became operational through August 31, 2004. Includes 78 miles of pipeline for Bossier Pipeline and 54 mile of pipeline for Katy Pipeline.

(d) Small Systems include: Chalkley, Rusk County, Whiskey Bay, Vantex, Ranger, Dorado, and Traders Creek.

(e) The Devon assets were acquired November 1, 2004 and will be added to the southeast Texas System. All information for these assets is based on Devon s prior historical information available.

Midstream and Transportation Operations. Our midstream and transportation operations are primarily located in major natural gas producing regions of Texas and Oklahoma. Our midstream and transportation assets, including the newly acquired ET Fuel System and the midstream assets acquired from Devon Energy Corporation on November 1, 2004, consist of our interests in approximately 7,750 miles of natural gas pipelines, four natural gas processing plants connected to our gathering systems with a total processing capacity of approximately 470 MMcf/d and thirteen natural gas treating facilities with a total treating capacity of approximately 1,050 MMcf/d. Our midstream and transportation operations relating to these assets consist of the following:

the gathering of natural gas from approximately 2,488 producing wells;

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the compression of natural gas to facilitate its flow from the wells through ETC OLP s gathering systems;

the treating and blending of natural gas to remove impurities such as carbon dioxide and hydrogen sulfide to ensure that the natural gas meets pipeline quality specifications;

the processing of natural gas to extract natural gas liquids, or NGLs; the sale of the pipeline quality natural gas, or residue gas, remaining after it is processed; and the sale of the NGLs to third parties at fractionation facilities where the NGLs are separated into their individual components, including ethane, propane, mixed butanes and natural gasoline;

the transportation of natural gas on the Oasis Pipeline, Bossier Pipeline, and ET Fuel Systems to industrial end-users, independent power plants, utilities and other pipelines; and

the purchase for resale of natural gas from producers connected to its systems and from other third parties.

Our midstream segment consists of the following:

the Southeast Texas System, a 4,179-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 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.

the Elk City System, a 318-mile gathering system located in western Oklahoma that gathers, compresses, treats and processes natural gas from the Anadarko Basin. The Elk City System also includes the Elk City processing plant and one treating facility. The Elk City System is connected, either directly or indirectly, to six major interstate and intrastate natural gas pipelines providing access to natural gas markets throughout the United States. The Elk City System has a processing capacity of approximately 130 MMcf/d.

The Elk City System is located in an area where certain producers are actively drilling in the Springer, Atoka and Arbuckle formations in western Oklahoma at depths in excess of 15,000 feet. We recently moved one of our treating plants from Texas to Beckham County, Oklahoma to treat natural gas produced in the western portion of the system. We believe that many of the producers in the area will choose to treat their gas through our new treating plant due to the lack of other competitive alternatives.

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 its assets, referred to as on-system gas, and attracts other customers by marketing volumes of natural gas that do not move through its 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 the Oasis Pipeline. We market only a small amount of natural gas that flows through our Elk City System.

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 segment consists of the following:

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

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

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

providing 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 14.0 Bcf of natural gas. Prior to our acquisition 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 (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 (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. 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 Bossier Pipeline is a 78-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 Bossier Pipeline expansion has initial capacity of 500 MMcf/d and currently has over 400 MMcf/d of pipeline capacity contracted under long-term agreements with XTO Energy Inc. and other producers.

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Heritage Operating, L.P.

We believe we are the fourth largest retail propane marketer in the United States, serving more than 650,000 customers from 310 customer service locations in 32 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. Since Heritage s inception through August 2004, we have completed 106 propane-related acquisitions for an aggregate purchase price of approximately $738 million. Volumes of propane sold to retail customers have increased from 63.2 million gallons for the fiscal year ended August 31, 1992 to 397.9 million gallons for the fiscal year ended August 31, 2004.

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

	For the Years Ended August 31,		
	2002	**2003**	**2004**
Retail Gallons Sold (in millions):	329.6	375.9	397.9

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 propane businesses, we will be best positioned to achieve our objectives.

We expect that midstream and transportation acquisitions, such as our recent acquisition of the ET Fuel 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 business will provide internal growth projects of greater scale compared to those available in our propane business.

Midstream and Transportation Business Strategies

Growth through acquisitions. As demonstrated by our recent acquisition of the ET Fuel System and our recent announcement of the Devon acquisition, we intend to make strategic acquisitions of midstream and transportation 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 and transportation 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 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.

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 Bossier Pipeline in east Texas and the

Fort Worth Basin project in North Texas, and construction of new facilities. Once completed, we expect that these expansions will lead to additional growth opportunities in this area.

Increase cash flow from fee-based businesses. Fee-based margin represents approximately 76% of our midstream and transportation segments   total gross margin for the year ended August 31, 2004. We generated approximately 29% of our gross margin during the year ended August 31, 2004 from fees charged for providing midstream services, including a transportation fee we charge our producer services business for natural gas that it transports on the Oasis Pipeline equal to the fee charged to third parties. This transportation fee accounted for 9% of total gross margin for this period. 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 expect the fee-based contracts associated with the Bossier Pipeline to significantly increase the fee-based component of our gross margin.

Propane Business Strategies

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.

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.

Competitive Strengths

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

Midstream and Transportation Business Strengths

We are diversified into major natural gas supply 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 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 recently completed Bossier Pipeline.

Our assets provide marketing flexibility through our access to numerous markets and customers. Our Oasis Pipeline combined with its 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. Additionally, our Elk City System has direct access to six major intrastate and interstate pipelines. With the acquisition of the ET Fuel System in June

2004, 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.

Our ability to bypass our La Grange and Elk City processing plants 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. In addition, we also have the option to not process natural gas at our Elk City processing plant because the gas produced in this area meets pipeline quality specifications without processing.

Propane Business Strengths

Experience in identifying, evaluating and completing acquisitions. Since inception through August 31, 2004, we completed 106 propane 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 us an attractive buyer for many propane acquisition candidates from the seller s viewpoint.

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.

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 2,600 full-time employees as of October 31, 2004, only 98, or approximately 4%, were general and administrative.

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

Midstream Natural Gas Industry Overview

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

Natural gas has a widely varying 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 material produced at the wellhead is 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 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 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 pipeline quality specifications 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 fractionation. NGL fractionation facilities separate mixed NGL streams into discrete NGL products: ethane, propane, isobutane, normal butane and natural gasoline. Ethane is primarily used in the petrochemical industry as feedstock for ethylene, one of the basic building blocks for a wide range of plastics and other chemical products. Isobutane is fractionated from mixed butane (a stream of normal butane and isobutane in solution) or refined from normal butane through the process of isomerization, principally for use to enhance the octane content of motor gasoline. Normal butane is used as a petrochemical feedstock in the production of ethylene and butadiene (a key ingredient in synthetic rubber), as a blendstock for motor gasoline and to derive isobutane through isomerization. Natural gasoline, a mixture of pentanes and heavier hydrocarbons, is used primarily as motor gasoline blend stock or petrochemical feedstock. We acquired a fractionation facility as part of the asset acquisition from Devon on November 1, 2004.

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

Propane Industry Overview

Propane, a by-product of natural gas processing and petroleum refining, is a clean-burning energy source recognized for its transportability and ease of use relative to alternative forms of stand-alone energy sources. Retail propane use falls into three broad categories: (i) residential applications, (ii) industrial, commercial and agricultural applications and (iii) other retail applications, including motor fuel sales. Residential customers use propane primarily for space and water heating. Industrial customers use propane primarily as fuel for forklifts, stationary engines, furnaces, as a cutting gas, in mining operations and in other process applications. Commercial customers, such as restaurants, motels, laundries and commercial buildings, use propane in a variety of applications, including cooking, heating and drying. In the agricultural market, propane is primarily used for tobacco curing, crop drying, poultry brooding and weed control. Other retail uses include motor fuel for cars and trucks, outdoor cooking and other recreational uses, propane resales and sales to state and local governments. In our wholesale operations, we sell propane principally to large industrial end-users and other propane distributors.

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 the nation s natural gas distribution systems 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 three to four 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. We also believe that our service capabilities and customer responsiveness differentiate us from many of these smaller competitors. Our employees are on call 24-hours-a-day, 7-days-a-week for emergency repairs and deliveries.

The wholesale propane business is highly competitive. For fiscal year 2004, 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 we believe that limited wholesale activities enhance our ability to supply our retail operations.

The Midstream and Transportation Segments

Competition

The business of providing natural gas gathering, transmission, treating, transporting and marketing services is highly competitive. Our principal areas of competition include obtaining natural gas supplies for the Southeast Texas System and Elk City System and natural gas transportation customers for the Oasis Pipeline, Bossier Pipeline, and the ET Fuel System. Our competitors include major integrated oil companies, interstate and intrastate pipelines and companies that gather, compress, treat, process, transport and market natural gas. The Southeast Texas System primarily competes with natural gas gathering and processing systems owned by Duke Energy Field Services. The Elk City System competes with natural gas gathering and processing systems owned by Enogex, Inc., Oneok Gas Gathering, L.L.C., CenterPoint Energy Field Services, Inc. and Enbridge, Inc., as well as producer-owned systems. The Oasis Pipeline competes directly with two other major intrastate pipelines that link the Waha Hub and the Houston area, one of which is owned by Duke Energy Field Services and the other, which is owned by El Paso and American Electric Power Service Corporation. The ET Fuel System and the Bossier Pipeline compete with various pipelines including those owned by Atmos Energy Corporation, Gulfterra Energy Partners, L.P., and Enbridge, Inc.

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, 2004, we had three customers that individually accounted for more than 10% of Midstream and Transportation segment revenues. While these customers represent a significant percentage of Midstream and Transportation segment revenues, the loss of any one of these customers 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. We do not own any interstate natural gas pipelines, 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. Failure to comply with the NGPA can result in the imposition of administrative, civil and criminal remedies.

Our intrastate pipeline 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, Oklahoma 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. Our operations in Oklahoma are regulated by the Oklahoma Corporation Commission through a complaint-based procedure. Under the Oklahoma Corporation Commission s regulations, we are prohibited from charging any unduly discriminatory fees for our gathering services and in certain circumstances are required to provide open access natural gas gathering for a fee. 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 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, 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 Act may result in the imposition of administrative, civil and criminal remedies. The rural gathering exemption under the Natural Gas Pipeline Safety Act of 1968 presently exempts substantial portions of our gathering facilities from jurisdiction under that statute. 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 Segments

Products, Services and Marketing

We distribute propane through a nationwide retail distribution network consisting of 310 customer service locations in 32 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 650,000 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. The capacity of these customer tanks ranges from approximately 100 gallons to 1,200 gallons, with a typical tank capacity of 100 to 300 gallons in milder climates and from 500 to 1,000 gallons in colder climates. We also deliver propane to retail customers in portable cylinders, which typically have a capacity of 5 to 35 gallons. When these cylinders are delivered to customers, empty cylinders are picked up for refilling at our distribution locations or are refilled on site. We also deliver propane to certain other bulk end-users of propane in tractor-trailer transports, which typically have an average capacity of approximately 10,500 gallons. End-users receiving transport deliveries include industrial customers, large-scale heating accounts, mining operations and large agricultural accounts.

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

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, 2004 were to retail customers and 3% were to wholesale customers. Of the retail gallons we sold, approximately 57% were to residential customers, 27% were to industrial, commercial and agricultural customers, and 16% 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 70% 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 21% of our gross profit from propane sales for the fiscal year ended August 31, 2004, 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. These figures are on a aggregate basis, which includes the historical figures of the operations of HOLP from the period from September 1, 2003 through August 31, 2004.

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, 2004 of 90% 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, 2004, Enterprise Products Operating L.P. (Enterprise) and Dynegy Liquids Marketing and Trade (Dynegy) provided approximately 24.9% and 18.8% of ours and Heritage s 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 19% of Heritage s combined total propane supply during the fiscal year ended August 31, 2004. 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, Dynegy and the supply procured by M-P Energy Partnership, no Still true?single supplier provided more than 10% of our total domestic propane supply during the fiscal year ended August 31, 2004. 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 no assurances can be given 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, South Carolina, 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.

Our propane distribution business is largely seasonal and dependent upon weather conditions in its service areas. Propane sales to residential and commercial customers are affected by winter heating season requirements. This generally results in 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.

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 relating to release of hazardous contaminants into the environment or otherwise relating to the protection of the environment. These laws and regulations can restrict or prohibit 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.

In most instances, the environmental laws and regulations affecting our operations relate to the potential release of substances or waste products into the air, water or soils and include measures to control or prevent the release of substances or waste products to the environment. Costs of planning, designing, constructing and operating pipelines, plants and other facilities must incorporate compliance with environmental laws and regulations and safety standards. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, which can include the assessment of monetary penalties, the imposition of remedial requirements, the issuance of injunctions and federally authorized citizen suits. Moreover, 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 substances or other waste products to the environment.

The clear trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus, there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. Moreover, risks of process upsets, accidental releases or spills are associated with our 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 not be able to pass on those increases to our customers. We will attempt to anticipate future regulatory requirements that might be imposed and plan accordingly in order to remain in compliance with changing environmental laws and regulations and to minimize the costs of such compliance.

The following is a discussion of certain environmental and safety concerns that relate to the midstream natural gas and NGLs industry. It is not intended to constitute a complete discussion of all applicable federal, state and local laws and regulations, or specific matters, to which ETC OLP may be subject.

Our operations are subject to the federal Clean Air Act and comparable state laws and regulations. These laws and regulations govern emissions of pollutants into the air resulting from our activities, for example in relation to our processing plants and our compressor stations, and also impose procedural requirements on how we conducts our operations. Such laws and regulations may include requirements that we obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions, strictly comply with the emissions and operational limitations of air emissions permits we are required to obtain, or utilize specific equipment or technologies to control emissions. Failure to comply with these requirements exposes us to civil enforcement actions from the state agencies and perhaps the EPA, including monetary penalties, injunctions, conditions or restrictions on operations and potentially criminal enforcement actions or federally authorized citizen suits.

Our operations generate wastes, including some hazardous wastes, that are subject to the federal Resource Conservation and Recovery Act (RCRA) and comparable state laws. However, RCRA currently exempts many natural gas gathering and field processing wastes from classification as hazardous waste. Specifically, RCRA excludes from the definition of hazardous waste produced waters and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy. Unrecovered petroleum product wastes, however, may still be regulated under RCRA as solid waste. Moreover, ordinary industrial wastes such as paint wastes, waste solvents, laboratory wastes and waste compressor oils, may be regulated as hazardous waste. The transportation of natural gas and NGLs in pipelines may also generate some hazardous wastes. Although we believe it is unlikely that the RCRA exemption will be repealed in the near future, repeal would increase costs for waste disposal and environmental remediation at our facilities.

Our operations could incur liability under the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA) and comparable state laws regardless of our fault, in connection with the disposal or other release of hazardous substances or wastes, including those arising out of historical operations conducted by our predecessors. Although petroleum as well as natural gas and NGLs are excluded from CERCLA s definition of hazardous substance, in the course of its ordinary operations we will generate wastes that may fall within the definition of a hazardous substance. CERCLA authorizes the Environmental Protection Agency (the EPA) and, in some cases, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other wastes released into the environment. If we were to incur liability under CERCLA, we could be subject to joint and several liability for the costs of cleaning up hazardous substances, for damages to natural resources and for the costs of certain health studies.

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, 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 hydrocarbons or wastes was not under our control. These properties and the substances 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 (including waste disposed of or released by prior owners or operators) or property contamination (including groundwater contamination, whether from prior owners or operators or other historic activities or spills) or to perform remedial plugging or pit closure operations to prevent future contamination, in some instances regardless of fault or the amount of waste we sent to the site. For example, we are currently involved in several remediation operations in which our cost for cleanup and related liabilities is estimated to be between $1.1 million and $1.8 million in the aggregate. However, with respect to one of the remedial projects, we expect to recover approximately $0.5 million to $0.8 million of these estimated cleanup costs pursuant to a contractual requirement that makes a predecessor owner responsible for environmental liabilities. We have established environmental accruals totaling approximately $0.5 million as of August 31, 2004 to address environmental conditions and related liabilities including costs for cleanup and remediation of properties.

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Our operations can result in discharges of pollutants to waters. The Federal Water Pollution Control Act of 1972, as amended (FWPCA), also known as the Clean Water Act, and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into state waters or waters of the United States. The unpermitted discharge of pollutants such as from spill or leak incidents is prohibited. The FWPCA and regulations implemented thereunder also prohibit discharges of fill material and certain other activities in wetlands unless authorized by an appropriately issued permit. 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 currently expect to incur costs of approximately $0.1 million over the next year to make spill prevention upgrades or modifications at certain of its facilities as required under its recently updated spill prevention controls and countermeasures or SPCC plans.

Our operations are subject to regulation by the U.S. Department of Transportation (the 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. The HLPSA covers crude oil, carbon dioxide, NGL and petroleum products pipelines and requires any entity which owns or operates pipeline facilities to comply with the regulations under the HLPSA, to permit access to and allow copying of records and to make certain reports and provide information as required by the Secretary of Transportation. We believe that our pipeline operations are in substantial compliance with applicable HLPSA requirements; however, due to the possibility of new or amended laws and regulations or reinterpretation of existing laws and regulations, there can be no assurance that future compliance with the HLPSA will not have a material adverse effect on our results of operations or financial positions.

Currently, the Department of Transportation, through the Office of Pipeline Safety, is in the midst of promulgating a series of rules intended to require pipeline operators to develop integrity management programs for gas transmission pipelines that, in the event of a failure, could impact high consequence areas . High consequence areas are currently defined as areas with specified population densities, buildings containing populations of limited mobility and areas where people gather that occur along the route of a pipeline. Similar rules are already in place for operators of hazardous liquid pipelines, which are also applicable to ETC OLP s pipelines in certain instances. The Office of Pipeline Safety has yet to publish a final rule requiring gas pipeline operators to develop integrity management plans, but it is expected that a rule will eventually be finalized. Compliance with such rule, or rules, when finalized, could result in increased operating costs that, at this time, cannot reasonably be quantified.

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

We do not believe that compliance with federal, state or local environmental laws and regulations will have a material adverse effect on our business, financial position or results of operations. In addition, we believe that the various environmental activities in which we are presently engaged are not expected to materially interrupt or diminish our operational ability to gather, compress, treat, process and transport natural gas and NGLs. We cannot assure you, however, that future events, such as changes in existing laws, the promulgation of new laws, or the development or discovery of new facts or conditions will not cause us to incur significant costs.

HOLP is subject to various federal, state and local environmental, health and safety laws and regulations. Generally, these laws impose limitations on the discharge of pollutants and establish standards for the handling of solid and hazardous wastes. These laws include, without limitation, RCRA, CERCLA, the Clean Air Act, the Occupational Safety and Health Act, the Emergency Planning and Community Right-to-Know Act, the Clean Water

Act and comparable state statutes. CERCLA, also known as the Superfund law, imposes joint and several liability in most instances, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to have contributed to the release or threatened release of a hazardous substance into the environment. Propane is not a hazardous substance within the meaning of CERCLA. However, certain automotive waste products generated by our truck fleet, as well as hazardous substances or hazardous waste disposed of during past operations by third parties on our properties, could subject us to liability under CERCLA. Such laws and regulations could result in civil or criminal penalties in cases of non-compliance and impose liability for remediation costs. In

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addition, third parties may make claims against owners or operators of properties for personal injuries and property damage associated with releases of hazardous or toxic substances or waste.

In connection with all acquisitions of retail propane businesses that involve the acquisition of any interests in real estate, we conduct an environmental review in an attempt to determine whether any substance other than propane has been sold from, or stored on, any such real estate prior to its purchase. Such review includes questioning the seller, obtaining representations and warranties concerning the seller s compliance with environmental laws and conducting inspections of the properties. Where warranted, independent environmental consulting firms are hired to look for evidence of hazardous substances or the existence of underground storage tanks.

Petroleum-based contamination or environmental wastes are known to be located on or adjacent to six sites, which we presently have or which we or our predecessors formerly had 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, we obtained indemnification for expenses associated with any remediation from the former owners or related entities. We have not been named as a potentially responsible party at any of these sites, nor have our operations contributed to the environmental issues at these sites. Accordingly, no amounts have been recorded in our August 31, 2004 consolidated balance sheets for any liability that may be attributable to any required remediation. Based on information currently available to us, such projects are not expected to have a material adverse effect on our financial condition or results of operations.

In July 2001, Heritage acquired a company that had previously received a request for information from 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 us was constructed, it is possible that the EPA may seek to recover all or a portion of groundwater remediation costs from private parties under CERCLA. Based upon information currently available to us, it is not believed that our liability, if such action were to be taken by the EPA, would have a material adverse effect on our financial condition or results of operations.

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 promulgated under the Federal Motor Carrier Safety Act. These regulations cover the transportation of hazardous materials and are administered by the United States Department of Transportation. We conduct ongoing training programs to help ensure that our operations are in compliance with applicable regulations. We maintain various permits that are necessary to operate our facilities, some of which may be material to our operations. 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 compliance in all material respects with applicable laws and regulations.

We have implemented environmental programs and policies designed to avoid potential liability and cost under applicable environmental laws. It is possible, however, that we will have increased costs due to stricter pollution control requirements or liabilities resulting from non-compliance with operating or other regulatory permits. It is not anticipated that our compliance with or liabilities under environmental, health and safety laws and regulations, including CERCLA, will have a material adverse effect on us. To the extent that there are any environmental liabilities unknown to us or environmental, health and safety laws or regulations are made more stringent, there can be no assurance that our results of operations will not be materially and adversely affected.

Employees

To carry out our operations for the midstream and transportation segments, we employ 301 people as of October 31, 2004. As of October 31, 2004, our propane operations had 2,600 full time employees, of whom 98 were general and administrative and 2,502 were operational employees. Of our operational employees, 52 are represented by labor unions. We believe that our relations with our employees are satisfactory. Historically, Heritage has also hired seasonal workers to meet peak winter demands in our propane operations.

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SEC Reporting

We electronically file certain documents with the SEC. We file annual reports on Form 10-K; quarterly reports on Form 10-Q; current reports on Form 8-K (as appropriate); along with any related amendments and supplements thereto. From time-to-time, we may also file registration and related statements pertaining to equity or debt offerings. You may read and copy any materials we file with the SEC at the SEC s Public Reference Room at 450 Fifth Street, NW, 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 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 its 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 are constructed on rights-of-way granted by the apparent record owners of the property. Lands over which pipeline rights-of-way have been obtained may be subject to prior liens that have not been subordinated to the right-of-way grants. We have obtained, where necessary, easement agreements from public authorities and railroad companies to cross over or under, or to lay facilities in or along, watercourses, county roads, municipal streets, railroad properties and state highways, as applicable. In some cases, property on which our pipeline was built was purchased in fee.

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 as described in this prospectus supplement. 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 an office building with 7,500 square feet of space for our executive offices in Dallas, Texas. We also lease office facilities in San Antonio, Texas, Tulsa, Oklahoma, and Helena, Montana, which consist of 39,235 square feet, 6,740 square feet, and 22,000 square feet, respectively. While we may require additional office space as our business expands, we believe that our existing facilities are adequate to meet its needs for the immediate future, and that additional facilities will be available on commercially reasonable terms as needed. We are currently in negotiations to replace our leased facility in Helena, Montana, which is for the administration of our propane operations, with a new building that we anticipate owning.

We operate bulk storage facilities at over 300 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 21.5 million gallons of above ground storage capacity at our various propane plant sites and have leased an aggregate of approximately 46 million gallons of underground storage facilities in New York, Georgia, Michigan, South Carolina, 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).

Prior to January 2004, Heritage owned a 50% interest in Bi-State Propane, a California general partnership that conducts business in California and Nevada. In January 2004, Heritage s subsidiary, Heritage Bi-State, L.L.C., acquired 100% of the assets of Bi-State Propane, and we conduct those operations under the tradename Bi-State Propane.

The transportation of propane requires specialized equipment. The trucks and railroad tank cars used for

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this purpose carry specialized steel tanks that maintain the propane in a liquefied state. As of August 31, 2004, we utilized approximately 52 transport truck tractors, 50 transport trailers, 10 railroad tank cars, 1,157 bobtails and 1,804 other delivery and service vehicles, all of which we own. As of August 31, 2004, we owned approximately 690,000 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 our obligations to our banks and the holders of our notes.

We utilize a variety of trademarks and tradenames in our propane operations that we own or have secured the right to use, including Heritage Propane. These trademarks and tradenames have been registered or are pending registration before the United States Patent and Trademark Office or the various jurisdictions in which the marks or tradenames 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, tradenames 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 such properties are subject to liabilities and leases, liens for taxes not yet due and payable, encumbrances securing payment obligations under non-competition agreements and immaterial encumbrances, easements and restrictions, we do not believe that any such burdens will materially interfere with our continued use of such properties in our business, taken as a whole. In addition, we believe that we have, or are in the process of obtaining, all required material approvals, authorizations, orders, licenses, permits, franchises and consents of, and have obtained or made all required material registrations, qualifications and filings with, the various state and local government and regulatory authorities which relate to ownership of our properties or the operations of our business.

ITEM 3. LEGAL PROCEEDINGS.

Although our 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, 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.

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 are a party, none have arisen outside the ordinary course of 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). 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. It is expected that the court will render a final judgment by the end of November 2004. SCANA has publicly stated that it plans to appeal any adverse judgment by the court. 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.

The Partnership 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 the Partnership. 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, the Partnership accrues the related deductible. As of August 31, 2004 and 2003, an accrual of $930 and $112, respectively, was recorded as accrued and other current liabilities on the Partnership s consolidated balance sheets.

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

On June 23, 2004, we held a special meeting for our Common Unitholders of record on May 17, 2004. At the meeting, our Common Unitholders approved (1) the change in the terms and conversion of all 7,721,542 outstanding Class D Units into 7,721,542 Common Units, (2) the change in the terms and conversion of all 3,742,515 outstanding Special Units into 3,742,515 Common Units upon the Bossier Pipeline becoming commercially operational, which occurred on June 21, 2004, and (3) our 2004 Unit Plan, which provides for awards of Common Units and other rights to our employees, officers and directors. The outcome of the vote to approve (a) a change in the terms of our Class D Units to provide that each Class D Unit convert into one of our Common Units and (b) the issuance of additional Common Units upon such conversion was 23,274,201 for, 647,923 against, 301,151 abstentions, and 0 broker non-votes. The approval of (a) a change in the terms of our Special Units to provide that each Special Unit convert into one of our Common Units upon the Bossier Pipeline becoming commercially operational and (b) the issuance of additional Common Units upon the Bossier Pipeline becoming commercially operational was 23,339,007 for, 579,583 against, 304,685 abstentions, and 0 broker non-votes. The Special Units voting as a separate class voted 3,605,894 for, 89,546 against, 47,074 abstentions, and 0 broker non-votes. At the special meeting, the votes cast with respect to the proposal to approve the terms of our 2004 Unit Plan was 23,108,023 for, 892,449 against, 222,754 abstentions, and 0 broker non-votes.

PART II

ITEM 5. MARKET FOR THE REGISTRANT S 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 period indicated.

	Price Range	Cash

	High	Low	Distribution (1)
2004 Fiscal Year			
Fourth Quarter Ended August 31, 2004	$43.38	$37.87	$ 0.8250
Third Quarter Ended May 31, 2004	$40.25	$34.50	$ 0.7500
Second Quarter Ended February 29, 2004	$42.66	$37.56	$ 0.7000
First Quarter Ended November 30, 2003	$38.70	$31.02	$ 0.6500

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	Price Range High	Price Range Low	Cash Distribution (1)
2003 Fiscal Year			
Fourth Quarter Ended August 31, 2003	$32.54	$29.60	$ 0.6500
Third Quarter Ended May 31, 2003	$29.90	$27.76	$ 0.6375
Second Quarter Ended February 28, 2003	$29.57	$27.05	$ 0.6375
First Quarter Ended November 30, 2002	$28.25	$24.50	$ 0.6375

(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.

Description of Units

As of September 30, 2004, there were approximately 42,800 individual Common Unitholders, which includes Common Units held in Street name. Common Units and Class C Units represent limited partner interest in the Name never changed any explanation needed?Partnership s Amended and Restated Agreement of Limited Partnership (the Partnership Agreement) that entitle the holders to the rights and privileges specified in the Partnership Agreement. As of August 31, 2004, we had 44,559,031 Common Units outstanding, of which 27,735,060 were held by the public, 15,883,234 were held by La Grange Energy or its affiliates, and 940,737 were held by our officers and directors. As of such date, the Common Units represent an aggregate 98.0% limited partner interest in the Partnership. Our General Partner owns an aggregate 2.0% general partner interest in the Partnership.

Common Units. Our Common Units are registered under the Securities Exchange Act of 1934 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 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. In conjunction with the transaction with U.S. Propane and the change of control of our General Partner in August 2000, we issued 1,000,000 newly created Class C Units to Heritage Holdings in conversion of that portion of its incentive distribution rights that entitled it to receive any distribution attributable to the net amount received by us in connection with the settlement, judgment, award or other final nonappealable resolution of specified litigation filed by us prior to the transaction with U.S. Propane, which we refer to as the SCANA litigation. The Class C Units have a zero initial capital account balance and were distributed by Heritage Holdings to its former stockholders in connection with the transaction with U.S. Propane.

On October 21, 2004, we announced that Heritage received a favorable jury verdict with respect to the SCANA litigation. The jury found in favor of Heritage on all four claims against SCANA, awarding a total of $48 million in actual and punitive damages. It is expected that the court will render a final judgment by the end of November 2004. SCANA has publicly stated that it plans to appeal any adverse judgment by the court. 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. All decisions of our General Partner relating to the SCANA litigation are determined by a special litigation committee consisting of one or more independent directors of our General Partner. As soon as practicable after the time that we receive any final cash 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 us by deducting from the amounts received all costs and expenses incurred by us and our affiliates in connection with the SCANA litigation and any cash reserves necessary or appropriate to provide for operating expenditures.

When the special litigation committee decides to distribute the distributable proceeds, the amount of the 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 be 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 we will receive any cash payments as a result of the SCANA litigation and, if so, when these distributions might be received.

The Class C Units do not have any rights to share in any of our assets or distributions upon dissolution and liquidation of our 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 the Class C Units 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 La Grange Energy, L.P. in connection with our acquisition of the ETC OLPoperations 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). 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 La Grange Energy in connection with the Energy Transfer Transaction) 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.

Class E Units. In conjunction with our purchase of the capital stock of Heritage Holdings in January 2004, the 4,426,916 Common Units held by Heritage Holdings were converted into 4,426,916 Class E Units. The Class E Units generally do not have any voting rights but were entitled to vote on the proposals to make 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 $2.82 per unit per year. We plan to leave the Class E Units in the form described here indefinitely. In the event of our 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 the Common Units. After the allocation 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 us with the opportunity to minimize the impact to us of our ownership of Heritage Holdings, including the $57.4 million in deferred tax liabilities of Heritage Holdings that we inherited in connection with our purchase of Heritage Holdings. The Class E Units are treated as treasury stock for accounting purposes because they are owned by our 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 us, as the owners of Heritage Holdings. Because distributions on the Class E Units will be available to us as the owner of Heritage Holdings, those funds will be available, after payment of taxes, for our General Partnership purposes, including to satisfy working capital requirements, for the repayment of outstanding debt and to make distributions to our 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 our 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 $2.82 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 La Grange Energy, L.P. on January 20, 2004 by us as consideration for the Bossier Pipeline in connection with the Energy Transfer Transactions. 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 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 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 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. The Class C Units were distributed by Heritage Holdings to its former shareholders. Any amount payable on the Class C Units in the future will reduce the amount otherwise distributable to holders of Incentive Distribution Rights at the time the distribution of such litigation proceeds is made and will not reduce the amount distributable to holders of Common Units. No payments to date have been made on the Class C Units.

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.

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

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. Our General Partner may make amendments to the Partnership Agreement without Unitholder approval to reflect:

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 partnership 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).

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. 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 continue 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 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.

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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.

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 $10.0 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 will 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 $0.50 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 $0.55 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 $0.635 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 $0.825 per unit for such quarter; (the third target distribution); and

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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 $2.82 per year. Please read Description of Units for a discussion of the Class C Units and the percentage interests in distributions of the different classes of units.

The total amount of distributions for the 2004 fiscal year on Common Units, the Class D Units, the Class E, the General Partner interests and the Incentive Distribution Rights totaled $76.7 million, $5.4 million, $6.2 million, $1.9 million and $4.3 million, respectively. All such distributions were made from Available Cash from operating surplus.

Changes in Securities and Recent Sales of Unregistered Securities

A total of 20,000 units were issued by the Partnership pursuant to the employment agreement with a former officer, Michael L. Greenwood following his retirement in August 2004. These units were not registered with the Securities and Exchange Commission and the Partnership relied on an exemption under section 4(2) of the Securities Act of 1933 for their issuance. All other issuances of unregistered securities during fiscal year 2004 have previously been reported in an applicable report for the period in which such issuances were made.

Equity Compensation Plan Information

At the time of its initial public offering, the shareholders of the Partnership s 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 the Partnership s 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	28,296 (1)	$1,410,839	
2004 Unit Plan	4,000 (1)	199,440	896,000

Equity compensation plans not approved by security holders:			
Total (2)	32,296	$ 1,610,279	896,000

(1) Valued as of October 29, 2004. Actual exercise price may differ depending on the Common Unit price on the date such units vest.

(2) As of August 31, 2004.

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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 acquiror 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 La Grange Energy s general partner contributed to ETC OLP its marketing business and its interest the Vantex System, the Rusk County Gathering System, the Whiskey Bay System and the Chalkley Transmission System.

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 has been derived from the audited consolidated financial statements of Aquila Gas Pipeline included elsewhere in this report. The financial information below for Aquila Gas Pipeline for the years ended December 31, 2000 and 1999 1998 has been derived from unaudited consolidated financial statements of Aquila Gas Pipeline, which are not included in this report or any other report.

The selected historical financial data should be read in conjunction with the financial statements of Energy Transfer Partners, L.P., ETC OLP, Aquila Gas Pipeline and Heritage Propane 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	
Year Ended December 31,			Nine Months Ended September 30,	Eleven Months Ended August 31,	Year Ended August 31,
1999	2000	2001	2002	2003(a)	2004
(unaudited)					

Statement of Operating Data:						
Revenues						
Midstream segment	$1,030,554	$1,758,530	$1,813,850	$933,099	$ 981,968	$1,988,163
Transportation segment					41,500	113,938
Propane segments						342,522
Other segment						37,631
Total revenues	1,030,554	1,758,530	1,813,850	933,099	1,023,468	2,482,254
Gross profit	94,109	117,663	98,589	53,035	121,965	356,104
Depreciation and amortization	27,061	30,049	30,779	22,915	13,461	50,848
Operating income	30,795	31,024	42,990	2,862	61,589	145,520
Interest expense	12,894	12,098	6,858	3,931	12,456	41,458
Income before income taxes	17,502	18,892	41,161	4,272	51,057	103,633
Provision for income taxes (b)	5,913	7,657	15,403	(467)	4,432	4,481
Net income	11,589	11,235	25,758	4,739	46,625	99,152
Net income share/unit (c)					6.90	3.45
Cash distribution share/unit						2.93

	Aquila Gas Pipeline				Energy Transfer	
	Year Ended December 31,			Nine Months Ended September 30,	Eleven Months Ended August 31,	Year Ended August 31,
	1999	2000	2001	2002	2003(a)	2004
	(unaudited)					
Balance Sheet Data (at period end):						
Current assets	108,552	231,260	144,396	116,831	185,180	436,882
Total assets	620,920	724,161	633,260	601,528	602,103	2,326,682
Current liabilities	160,419	313,506	194,816	144,076	169,473	397,460
Long-term debt	163,273	110,721	66,250	66,250	196,000	1,070,871
Stockholders equity/Partners equity	237,877	254,248	249,520	254,259	181,088	746,980
Other Financial Data:						
EBITDA, as adjusted (unaudited) (d)	57,457	61,039	78,798	31,118	77,476	196,918
Cash flow provided by operating activities	43,182	76,011	65,198	12,987	70,916	162,695
Cash flow used in investing activities	(13,785)	(23,459)	(20,727)	(487)	(310,160)	(790,737)
Cash flow provided by (used in) financing activities	(34,544)	(52,552)	(44,471)	(12,500)	292,366	656,665
Capital expenditures (e)						
Maintenance and Growth	19,166	26,866	23,944	5,486	13,872	109,688
Acquisition					306,131	681,835

(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.

(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. Although the equity account of ETC OLP survive the Energy Transfer Transactions, Heritage s partnership structure and partnership units survive. Accordingly, the equity account of ETC OLP have been restated based on general partner interest and Common Units received by ETC OLP in the Energy Transfer Transactions.

(c) 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.

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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 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					
	Year Ended August 31, 1999	**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**
Net income reconciliation						
Net income	$11,589	$11,235	$25,758	$ 4,739	$46,625	$ 99,152
Depreciation and amortization	27,061	30,049	30,779	22,915	13,461	50,848

Interest	12,894	12,098	6,858	3,931	12,456	41,458
Taxes	5,913	7,657	15,403	(467)	4,432	4,481
Non-cash compensation expense						42
Interest income and other					(501)	(509)
Depreciation, amortization, and interest and taxes of investee					1,003	440
(Gain) loss on disposal of assets						1,006
EBITDA, as adjusted (a)	$57,457	$61,039	$78,798	$31,118	$77,476	$196,918

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Heritage

The following table sets forth, for the periods and as of the dates indicated, selected historical financial and operating data for Heritage and its subsidiaries. The selected historical financial and operating data should be read in conjunction with the financial statements of Heritage included elsewhere in this report and Management s Discussion and Analysis of Financial Condition and Results of Operations also included elsewhere in this report. The amounts in the table below, except per unit data, are in thousands.

	Years Ended August 31,		
	2001	2002	2003
Statement of Operating Data:			
Revenues	$ 543,975	$462,325	$571,476
Gross profit (a)	237,419	224,140	274,320
Depreciation and amortization	40,431	36,998	37,959
Operating income	54,423	40,961	70,193
Interest expense	35,567	37,341	35,740
Income before income taxes and minority interests	20,524	5,476	33,041
Provision for income taxes			1,023
Net income	19,710	4,902	31,142
Net income per unit (b)	1.43	0.25	1.79
Cash distributions per unit	2.38	2.55	2.56
Balance Sheet Data:			
Current assets	$ 138,263	$ 95,387	$ 94,138
Total assets	758,167	717,264	738,839
Current liabilities	127,655	122,069	151,027
Long-term debt	423,748	420,021	360,762
Minority interests	5,350	3,564	4,002
Partners capital - general partner (b)	1,875	1,585	2,190
Partners capital - limited partners (b)	206,080	173,677	221,207
Operating Data (unaudited):			
EBITDA, as adjusted (c)	$ 97,444	$ 81,536	$110,963
Cash flows from operating activities	28,056	65,453	95,199
Cash flows used in investing activities	(122,313)	(33,412)	(48,389)
Cash flows from (used in) financing activities	95,038	(33,071)	(44,289)
Capital expenditures (d)			
Maintenance and growth	23,854	27,072	27,294
Acquisition	94,860	19,742	24,956
Retail gallons sold	330,242	329,574	375,939

(a) Gross profit is computed by reducing total revenues by the direct cost of the products sold.

(b) Net income per unit is computed by dividing the limited partner s interest in net income by the weighted average number of units outstanding.

(c)

EBITDA, as adjusted, is defined as Heritage 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. Heritage presented 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 Heritage 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 Heritage 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 propane industry and for master limited partnerships as an indicator of the strength and performance of Heritage 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 Heritage s investors for trending, analyzing and benchmarking the operating results of Heritage 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 Heritage s performance in a manner similar to the methods used by management and provides additional insight to Heritage 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 Heritage s numerous business locations, as a measure for evaluating targeted businesses for acquisition and as a measurement component of incentive compensation. The Heritage had 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. Heritage s 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 Heritage 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 Heritage s. Other expenses include other finance charges and other asset non-cash impairment charges that are reflected in Heritage 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 performance measure in a manner that is not related to the true operating results of the Partnership s business. In addition, Heritage s 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, Heritage s 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 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, and cash flow from operating activities. A reconciliation of EBITDA, as adjusted, to net income is presented below. Please read -Reconciliation of EBITDA, As Adjusted, to Net Income below.

(d) Capital expenditures fall generally into three categories: (i) maintenance capital expenditures of approximately $15.1 and $12.8 million in fiscal years 2003, and 2002, respectively, which include expenditures for repairs that extend the life of the assets and replacement of property, plant and equipment, (ii) growth capital expenditures, which include expenditures for purchase of new propane tanks and other equipment to facilitate retail customer base expansion, and (iii) acquisition expenditures which include

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expenditures related to the acquisition of retail propane operations and other business, and the portion of the purchase price allocated to intangibles associated with such acquired businesses.

Reconciliation of EBITDA, As Adjusted, to Net Income

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

	Years Ended August 31,		
	2001	**2002**	**2003**
Net income reconciliation			
Net income	$19,710	$ 4,902	$ 31,142
Depreciation and amortization	40,431	36,998	37,959
Interest	35,567	37,341	35,740
Taxes			1,023
Non-cash compensation expense	1,079	1,878	1,159
Other expenses	394	294	3,213
Depreciation, amortization, and interest and taxes of investee	792	743	901
Minority interest in the Operating Partnership	283	192	256
Less: Gain on disposal of assets	(812)	(812)	(430)
EBITDA, as adjusted (a)	$97,444	$81,536	$110,963

(a) Please read footnote (c) under Item 6. Selected Historical Financial and Operating Data Heritage Propane Partners L.P. and Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Description of Indebtedness for a more detailed discussion of EBITDA, as adjusted.

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

Energy Transfer Partners, L.P. (the Registrant or Partnership), is a Delaware limited partnership. The Partnership s 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.

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.

Forward-Looking Statements

Certain matters discussed in this report, excluding historical information, as well as some statements by the Partnership in periodic press releases and some oral statements of Energy Transfer Partners 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. Statements using words such as anticipate, believe, intend, project, plan, continue, estimate, forecast, may, expressions help identify forward-looking statements. Although the Partnership believes such forward-looking statements are based on reasonable assumptions and current expectations and projections about future events, no assurance can be given that every objective will be reached.

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Actual results may differ materially from any results projected, forecasted, estimated or expressed in forward-looking statements since many of the factors that determine these results are subject to uncertainties and risks, difficult to predict, and beyond management s control. Such factors include:

- **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 Energy Transfer s pipelines and gathering systems;**
- **the level and throughput in Energy Transfer s natural gas processing and treating facilities;**
- **the fees ETC OLPcharges 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;

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loss of key personnel;

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

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 Energy Transfer s liquids marketing counterparties to satisfy their financial commitments and the nonpayment or nonperformance by its customers;

the availability and cost of capital and Energy Transfer s 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 the Partnership s financial results; and

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

Energy Transfer Transactions

On January 20, 2004, Heritage and La Grange Energy completed the series of transactions whereby La Grange Energy 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 La Grange Energy 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 La Grange Energy and an affiliate of La Grange Energy contributed an office building to ETC OLP. La Grange Energy also received 3,742,515 Special Units as consideration for the project it had in progress to construct the Bossier Pipeline. The Special Units converted to Common Units upon the Bossier Pipeline becoming commercially operational and such conversion being approved by Energy Transfer s Unitholders. The Bossier 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, La Grange Energy obtained control of Heritage by acquiring all of the interest in U.S. Propane, L.P., (U.S. Propane) the General Partner of Heritage, and U.S. Propane, L.P. s general partner, 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, U.S. Propane L.P. 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.

Other Recent Transactions

On June 2, 2004, we announced the closing of the acquisition of the midstream natural gas assets of TXU Fuel Company, a gas transportation subsidiary of TXU Corp., which we refer to as the TUFCO acquisition, for approximately $500.0 million in cash, subject to post-closing adjustments. The former TUFCO System, which we refer to as the ET Fuel System, serves some of the most active drilling areas in the United States. The ET Fuel System is comprised of approximately 2,000 miles of intrastate natural gas pipeline and related natural gas storage facilities located in Texas. 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.

On November 1, 2004 we announced the closing of the acquisition of certain midstream natural gas assets of Devon Energy Corporation (Devon) for approximately $64.6 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.

General

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.

Midstream and transportation segments

Our midstream and transportation segments are operated by ETC OLP. These segments commenced operations in October 2002 with ETC OLP s acquisition of the natural gas gathering, processing and transportation assets previously owned by Aquila, Inc. The assets acquired from Aquila include the Southeast Texas system and the Oklahoma system as well as a 50% equity interest in the Oasis Pipe Line Company (Oasis). ETC OLP purchased the remaining 50% interest in Oasis Pipeline on December 27, 2002. The equity method of accounting was used to account for our Oasis Pipeline from October 1, 2002 through December 27, 2002 at which time it became a fully consolidated subsidiary.

We own and operate approximately 7,750 miles of natural gas gathering and transportation pipelines with an aggregate throughput capacity of 5.2 billion cubic feet of natural gas per day, with natural gas treating and processing plants located in Texas, Oklahoma, and Louisiana. Our major asset groups consist of the Southeast Texas System, the Elk City System, the Oasis Pipeline, the ET Fuel System, and the Bossier Pipeline. The Southeast Texas System has a throughput capacity of 2,300 MMcf/d and includes approximately 4,200 miles of pipeline with approximately 2,050 wells connected, the La Grange and Madison processing plants, and ten natural gas treating facilities. The Elk City System has a throughput capacity of 815 MMcf/d and includes approximately 318 miles of pipeline with 300 wells connected, the Elk City processing plant, and a treating facility. The 583 mile long Oasis pipeline, which connects the West Texas Waha Hub to the Katy Texas Tailgate, has a throughput capacity of 1.2 Bcf/d. 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. The ET Fuel System is strategically located near high-growth production areas and major centers such as the Waha Hub, the Katy Hub, and the Carthage Hub and has a throughput capacity of 1.3 Bcf/d. The Bossier Pipeline is a 78-mile natural gas pipeline that connects three treating facilities with our Southeast Texas Assets of which, one treating facility is owned by us. This Bossier Pipeline is the first phase of a multi-phased project that will service producers in East and North Central Texas. The Bossier Pipeline has throughput capacity of 500 MMcf/d and currently has over 400 MMcf/d of pipeline capacity contracted under long-term agreements with XTO Energy Inc. and other producers.

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 its 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, 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, 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.

Our ownership of the Oasis Pipeline allows us to elect not to process natural gas at the La Grange processing plant when processing margins are unfavorable. We can bypass the La Grange processing plant and deliver natural gas meeting pipeline quality specifications by blending rich natural gas from the Southeast Texas System with lean natural gas transported on the Oasis Pipeline. We can also generally bypass the Elk City processing plant. The natural gas supplied to the Elk City System has a relatively low NGL content and does not require processing to meet pipeline quality specifications. During periods of unfavorable processing margins, we can bypass the Elk City processing plant and deliver the natural gas directly into connecting pipelines.

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, and attracts 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.

Our marketing activities involve the marketing of on-system and off-system gas. For the fiscal year ended August 31, 2004, we marketed approximately 975 MMcf/d of natural gas, 49% of which was on-system gas. Substantially all of our on-system marketing efforts involve natural gas that flows through either the Southeast Texas System or the Oasis Pipeline. We market only a small amount of natural gas that flows through the Elk City System.

For 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, which facilitates our 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.

Results from our transportation 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 on the Oasis Pipeline, (iii) a fuel retention based on a percentage of gas transported on the pipeline, or a combination of the three, generally payable monthly.

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, domestic wholesale and foreign wholesale propane segments, (the propane segments) and also through the liquids marketing activity of Heritage Energy Resources. HOLP derives its revenue primarily from the retail propane segment. We believe that Heritage was, and we are now, the fourth largest retail marketer of propane in the United States, based on retail gallons sold. We serve more than 650,000 propane customers in from 310 customer service locations in 32 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 will 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 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 for future resale.

Our retail propane business of the Partnership 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.

Since its formation in 1989, Heritage grew primarily through acquisitions of retail propane operations and, to a lesser extent, through internal growth. Since its inception through January 19, 2004, Heritage completed 103 acquisitions for an aggregate purchase price approximating $720 million. Since the Energy Transfer Transactions on January 20, 2004 through August 31, 2004, we have completed three additional retail propane acquisitions.

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 Heritage s retail propane volume and in excess of 80% of Heritage 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 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. 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 (the foreign wholesale propane segment). 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

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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 (see note 2 to the Partnership s consolidated financial statements). 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, and of 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.

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

Volume. Total volumes of natural gas sales, NGL sales including propane, and natural gas transported by our midstream, transportation, 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	Year Ended August 31, 2004	Eleven Months Ended August 31, 2003	Year Ended August 31, 2003
	(actual)	(Aggregate unaudited)	(ETC OLP actual)	(Aggregate unaudited)
Midstream				
Natural gas MMBtu/d	975,000	975,000	524,000	524,000
NGLs bbls/d	12,000	12,000	13,000	13,000
Transportation				
Natural gas MMBtu/d	1,091,000	1,091,000	921,000	921,000
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

Natural gas sales volumes were 975,000 MMBtu/d for the year ended August 31, 2004 compared to 524,000 MMBtu/d for the eleven months ended August 31, 2003, an increase of 451,000 MMBtu/d or 86.1%. NGLs sales volumes decreased 7.7% from 13,000 Bbls/d for the eleven months ended August 31, 2003 to 12,000 Bbls/d for the year ended August 31, 2004. The increased natural gas sales volumes are 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 varies 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.

Total retail propane gallons sold in the twelve months ended August 31, 2004 were 226.2 million gallons, with no retail propane gallons reflected in the year 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 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.

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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 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.

Set forth in the table below is certain financial data for the periods presented.

	Year Ended August 31, 2004	Year Ended August 31, 2004	Eleven Months Ended August 31, 2003	Year Ended August 31, 2003
	(Actual)	(Aggregate) (unaudited)	(ETC OLP)	(Aggregate) (unaudited)
Midstream Segment:				
Revenues	$1,988,163	$1,988,163	$ 981,968	$ 981,968
Cost of sales	1,904,777	1,904,777	899,420	899,420
Operating expenses	17,267	17,267	14,107	14,107
General and administrative	13,052	13,052	10,944	10,944
Depreciation and amortization	11,886	11,886	10,647	10,647
Unrealized gains (losses) on derivatives	25,499	25,499	(2,950)	(2,950)
Segment operating income	$ 66,680	$ 66,680	$ 43,900	$ 43,900
Transportation Segment:				
Revenues	$ 113,938	$ 113,938	$ 41,500	$ 41,500
Cost of sales	11,270	11,270	2,123	2,123
Operating expenses	30,571	30,571	13,853	13,853
General and administrative	8,372	8,372	5,021	5,021
Depreciation and amortization	7,426	7,426	2,814	2,814
Segment operating income	$ 56,299	$ 56,299	$ 17,689	$ 17,689
Retail Propane Segment:				
Retail propane revenues	$ 315,177	$ 536,636	$	$ 463,392
Other revenues	36,768	64,697		59,385
Liquids marketing	863	1,232		1,333
Retail propane cost of sales	174,769	296,206		236,307
Other cost of sales	10,463	18,816		17,213
Operating expenses	102,326	162,086		148,623
Depreciation and amortization	31,104	46,299		37,442

Segment operating income	$ 34,146	$ 79,158	$	$ 84,525
Wholesale Propane Segment:				
Revenues	$ 5,358	$ 9,394	$	$ 10,719
Cost of sales	4,742	8,345		9,620
Operating expenses	1,936	2,911		3,508
Depreciation and amortization	417	601		494
Segment operating loss	$ (1,737)	$ (2,463)	$	$ (2,903)
Foreign Wholesale Segment:				
Revenues	$ 21,987	$ 38,547	$	$ 36,647
Cost of sales	20,129	35,065		34,016
Depreciation and amortization	15	25		23
Segment operating income	$ 1,843	$ 3,457	$	$ 2,608
Unallocated selling, general and administrative expenses	$ 11,711	$ 21,811	$	$ 14,037
Consolidated Information:				
Revenues	$ 2,482,254	$ 2,752,607	$ 1,023,468	$ 1,594,944
Cost of sales	2,126,150	2,274,480	901,543	1,198,699
Gross profit	356,104	478,127	121,925	396,245

	Year Ended August 31, 2004	Year Ended August 31, 2004	Eleven Months Ended August 31, 2003	Year Ended August 31, 2003
	(Actual)	(Aggregate) (unaudited)	(ETC OLP)	(Aggregate) (unaudited)
Operating expenses	152,100	212,835	27,960	180,091
Selling, general and administrative	33,135	43,234	15,965	30,002
Depreciation and amortization	50,848	66,237	13,461	51,420
Unrealized gains (losses) on derivatives	25,499	25,499	(2,950)	(2,950)
Consolidated operating income	$145,520	$181,320	$61,589	$131,782
Equity in earnings of affiliates	363	859	1,423	2,794
Interest expense	41,458	54,212	12,456	48,196
Gain (loss) on disposal of assets	(1,006)	(1,246)		430
Other income (expense)	509	443	501	(2,712)
Minority interests	(295)	(867)		(876)
Income tax expense	4,481	4,501	4,432	5,455
Net income	$ 99,152	$121,796	$46,625	$ 77,767

Revenues. Total revenues were $2,482.3 million for the fiscal year ended August 31, 2004 compared to $1,023.5 million for the eleven months ended August 31, 2003. These revenues reflect a full twelve months of ETC OLP s revenues consolidated with the revenues of HOLP after the Energy Transfer Transactions occurred (from January 20, 2004 through August 31, 2004). The aggregate revenues for the periods presented would have been total revenues of $2,752.6 million for the year ended August 31, 2004 as compared to aggregate total revenues of $1,594.9 million for the year ended August 31, 2003.

Total midstream and transportation revenues were $2,102.1 million for the year ended August 31, 2004 compared to $1,023.5 million for the eleven months ended August 31, 2003, an increase of $1,078.6 million or 105.4%. Midstream revenues increased $1,006.2 million or 102.5% from $982.0 million for the eleven months ended August 31, 2003 to $1,988.2 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.

Our average natural gas sales prices were $5.16 per MMBtu for the year ended August 31, 2004 compared to $5.03 per MMBtu for the eleven months ended August 31, 2003. Average NGLs sales prices increased $0.16 or 39% from $0.41 per gallon for the eleven months ended August 31, 2003 compared to $0.57 per gallon for the year ended August 31, 2004. The market price for NGLs tends to correlate with the price of crude oil.

Transportation revenues were $113.9 million for the year ended August 31, 2004 compared to $41.5 million for the eleven months ended August 31, 2003, an increase of 174.5%. The significant increase in transportation 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. Had Oasis Pipeline been consolidated for the entire 2003 reporting period, transportation revenues would have been $49.5 million for the eleven months ended August 31, 2003.

Increased volumes. During the year ended August 31, 2004, we transported 1,091,000 MMBtu/d through our transportation pipelines compared to 921,000 MMBtu/d during the period from December 27, 2002 to August 31, 2003, an increase of 170,000 MMBtu/d or 18.5%. 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 Bossier Pipeline in June 2004. The ET Fuel System and Bossier Pipeline contributed $18.9 million in revenues from the date of acquisition or completion through August 31, 2004. We believe that we will be able to increase throughput on, and therefore revenue 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.

For the fiscal year ended August 31, 2004, we had retail propane revenues of $315.2 million, domestic wholesale propane revenues of $5.4 million, foreign wholesale propane revenues of $22.0 million, other revenues of $36.8 million and net liquids marketing activities of $0.8 million with no propane revenues reflected in the eleven months 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 historical 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. Aggregate domestic wholesale propane revenues were $9.4 million for the fiscal year ended August 31, 2004 as compared to historical $10.7 million for the fiscal year ended August 31, 2003. Of the decrease, $2.2 million is due to the lost commercial customers described above, offset by a $0.9 million increase related to higher selling prices. Aggregate foreign wholesale propane revenues were $38.5 million as compared to historical results of $36.6 million for the fiscal year ended August 31, 2003, due to a $7.1 million increase related to higher selling prices offset by a decrease of $5.2 million due to the decrease in volumes described above. Aggregate other revenues were $64.7 million compared to $59.4 million for the fiscal year ended August 31, 2003, and net liquids marketing activities would have been $1.2 million as compared to $1.3 million for the fiscal year ended August 31, 2003.

Costs of Sales. Total cost of products sold increased to $2,126.2 million for the fiscal year ended August 31, 2004 as compared to $901.5 million for the eleven months ended August 31, 2003. These costs of sales reflect the full twelve months of ETC OLP s cost of sales consolidated with the cost of sales of HOLP after the Energy Transfer Transactions (from January 20, 2004 through August 31, 2004). Aggregate total cost of sales for the periods presented, would have been $2,274.5 million for the fiscal year ended August 31, 2004 as compared to the aggregate total cost of sales of $1,198.7 million for the year ended August 31, 2003.

Total cost of sales for our midstream and transportation segments was $1,916.0 million for the year ended August 31, 2004 compared to $901.5 million for the eleven months ended August 31, 2003, an increase of $1,014.5 million or 112.5%.

Midstream cost of sales was $1,904.8 million for the year ended August 31, 2004 compared to $899.4 million for the eleven months ended August 31, 2003, an increase of $1,005.4 million or 111.8%. The increase is principally attributable to the increase in sales volumes and prices during the year ended August 31, 2004 as we have expanded our marketing efforts. Transportation cost of sales was $11.3 million for the year ended August 31, 2004 and $2.1 million for the eleven months ended August 31, 2003. The transportation segment generally retains a portion of each shipper s gas to compensate for fuel used in operating the pipeline. The actual usage of gas can differ from the amounts retained from our customers. Cost of sales activity is typically generated from the sale of excess inventory or the recognition, either positive or negative, of unaccounted fuel within the pipeline system.

For the fiscal year ended August 31, 2004, we had retail propane cost of sales of $174.8 million, domestic wholesale propane cost of sales of $4.7 million, foreign wholesale propane cost of sales of $20.1 million, and other cost of sales of $10.5 million with no 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. Aggregate domestic wholesale propane cost of sales would have been $8.3 million as compared to historical cost of sales of $9.6 million for the fiscal year ended August 31, 2003. Of the decrease, $1.9 million is due to volume decreases described above offset by $0.6 million increase due to increased selling prices. Aggregate foreign wholesale propane cost of sales would have been $35.1 million as compared to historical cost of sale of $34.0 million for the fiscal year ended August 31, 2003. Of the increase, $5.8 million is related to higher selling prices offset by a decrease of $4.7 million due to volume decreases described above. Aggregate other cost of sales would $18.8 million as compared to historical other cost of sales of $17.2 million for the fiscal year ended August 31, 2003.

Operating Expenses. Operating expenses increased $124.1 million to $152.1 million for the fiscal year ended August 31, 2004 as compared to $28.0 million for the eleven months ended August 31, 2003. These operating expenses reflect a full fiscal year of ETC OLP s operating expenses consolidated with the operating expenses of HOLP after the Energy Transfer Transactions (from January 20, 2004 through August 31, 2004). Aggregate total operating expenses for the periods presented would have been $212.8 million for the fiscal year ended August 31, 2004 as compared to the aggregate total operating expenses of $180.1 million for the year ended August 31, 2003.

Total midstream and transportation operating expenses were $47.8 million for the year ended August 31, 2004 compared to $28.0 million for the eleven months ended August 31, 2003, an increase of $19.8 million or 70.7%.

Midstream operating expenses increased from $14.1 million for the eleven months ended August 31, 2003 to $17.3 million for the year ended August 31, 2004. The increase was principally attributable to a $1.6 million effect of reporting on an additional month during the year ended August 31, 2004 compared to the eleven months ended August 31, 2003, a $0.7 million increase in plant expenses due to the completion of a new plant in August 2003, and an increase in chemical expense due to increased throughput. Transportation 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 Bossier Pipeline in June 2004.

Total operating expenses for the propane operations were $104.3 million for the fiscal year ended August 31, 2004, which reflects from the date of the Energy Transfer Transaction. Our propane operations would have reflected total aggregate operating expense of $165.0 million for the full year as compared to Heritage s historical total operating expenses of $152.1 million for the year ended August 31, 2003, or an increase of $12.9 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.

Selling, General and Administrative Expenses. Selling, general and administrative expenses were $33.1 million for the fiscal year ended August 31, 2004 compared to $16.0 million for the eleven months ended August 31, 2003. Of this increase, $4.5 million is due to the Energy Transfer Transactions described above. These selling, general and administrative expenses reflect the full fiscal year of ETC OLP s selling, general and administrative expenses consolidated with the selling, general and administrative expenses of HOLP after the Energy Transfer Transactions (from January 20, 2004 through August 31, 2004). Aggregate total selling, general, and administrative expenses for the periods presented, would have been $43.2 million for the fiscal year ended August 31, 2004 as compared to the aggregate total of $30.0 million for the year ended August 31, 2003. Total general and administrative operating expenses for our midstream and transportation segments were $21.4 million for the year ended August 31, 2004 compared to $16.0 million for the eleven months ended August 31, 2003, an increase of $5.4 million or 33.8%. Midstream general and administrative expenses increased 19.3% or $2.1 million from $10.9 million for the eleven months ended August 31, 2003 to $13.0 million principally due to a $1.2 million effect of reporting on an additional month for the year ended August 31, 2004, a $2.5 million increase in compensation expense related to our producer services, 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 segment for certain management services provided by the midstream. Transportation general and administrative expenses also 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. Selling, general and administrative expenses are not allocated to our propane segments. The total unallocated selling, general, and administrative expenses were $11.7 million for the fiscal year ended August 31, 2004, which includes $4.1 million of total unallocated Partnership selling, general and administrative expenses. On as aggregate basis, these unallocated selling general and administrative expenses would have been $21.8 million for the full twelve months ended August 31, 2004, with $8.1 million of Partnership selling, general and administrative expenses as compared to the historical amount of $14.0 million for the fiscal year ended August 31, 2003 for Heritage.

Depreciation and Amortization. Depreciation and amortization expense for the fiscal year ended August 31, 2004 was $50.8 million compared to $13.5 million for the eleven months ended August 31, 2003, an increase of $37.3 million. This depreciation and amortization reflects the full fiscal year of ETC OLP s depreciation and amortization consolidated with the depreciation and amortization of HOLP after the Energy Transfer Transactions (from January 20, 2004 through August 31, 2004). Of the increase, $31.5 million is due to the Energy Transfer Transactions for the depreciation on our propane assets from January 20, 2004 through August 31, 2004. Midstream depreciation and amortization increased $1.2 million or 11.3% from $10.6 million for the eleven months ended August 31, 2003 to $11.9 million for the year ended August 31, 2004 due to an additional month in the 2004 reporting period. Transportation depreciation and amortization increased $4.6 million or 164.3% 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.

Operating Income. For the fiscal year ended August 31, 2004, we had operating income of $145.5 million as compared to operating income of $61.6 million for the eleven months ended August 31, 2003. This increase is primarily due the Energy Transfer Transactions and changes in revenues and expenses described above. This operating income reflects the full fiscal year of ETC OLP s operating income consolidated with the operating income of HOLP after the Energy Transfer Transactions (from January 20, 2004 through August 31, 2004). Aggregate total operating income for the periods presented, would have been $181.3 million for the fiscal year ended August 31, 2004 as compared to $131.8 million for the year ended August 31, 2003.

Unrealized/Realized Gain (Loss) on Derivatives. The unrealized gain on derivatives was $25.5 million for the fiscal year ended August 31, 2004 compared to an unrealized loss of $3.0 million for the eleven months ended August 31, 2003. Derivative price changes worked to our favor during the 2004 reporting period compared to the 2003 reporting period.

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 $41.5 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 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.

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

EBITDA, as adjusted. EBITDA, as adjusted, increased $119.4 million to $196.9 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 $249.8 million for the

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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, 2004	August 31, 2003	August 31, 2003	August 31, 2003
	(Actual)	(Aggregate)	(ETC OLP)	(Aggregate)	(Heritage Historical)
Net income reconciliation					
Net income	$ 99,152	$121,796	$46,625	$ 77,767	$ 31,142
Depreciation and amortization	50,848	66,237	13,461	51,420	37,959
Interest	41,458	54,212	12,456	48,196	35,740
Taxes	4,481	4,501	4,432	5,455	1,023
Non-cash compensation expense	42	1,274		1,159	1,159
Other expense (income)	(509)	(443)	(501)	2,712	3,213
Depreciation, amortization, and interest of investee	440	762	1,003	1,904	901
Minority interests in Operating Partnership		178		256	256
(Gain) loss on disposal of assets	1,006	1,246		(430)	(430)
EBITDA, as adjusted (a)	$196,918	$249,763	$77,476	$188,439	$110,963

(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.

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.

Eleven Months Ended August 31, 2003 For ETC OLP Compared to Nine Months Ended September 30, 2002 for Aquila Gas Pipeline Corporation

Revenues. Total revenues were $1,023.5 million for the eleven months ended August 31, 2003 compared to $933.1 million for the nine months ended September 30, 2002, an increase of $90.4 million or 9.7%. Midstream revenues were $982.0 million for the eleven months ended August 31, 2003 compared to $933.1 million for the nine months ended September 30, 2002, an increase of $48.9 million or 5.2%. The increase is primarily due to the difference in the number of operating periods. In order to fully understand the results of operations, we have also considered the impact of volumes and prices on our business as noted below.

Natural gas sales volumes were 524,000 MMBtu/d for the eleven months ended August 31, 2003 compared to 1,147,000 MMBtu/d for the nine months ended September 30, 2002, a decrease of 623,000 MMBtu/d or 54.3%. NGL sales volumes were 13,000 Bbls/d for the eleven months ended August 31, 2003 compared to 19,000 Bbls/d for the nine months ended September 30, 2002, a decrease of 6,000 Bbls/d or 31.6%. Natural gas sales volumes decreased significantly as a result of the smaller scope of our marketing activities as compared to Aquila Gas Pipeline s (the Predecessor) extensive marketing and trading activities. NGL sales volumes decreased due to our frequent election to bypass its La Grange processing plant and deliver unprocessed natural gas from our Southeast Texas System directly into the Oasis Pipeline during the portion of the eleven month period ended August 31, 2003 when we owned 100% of Oasis Pipeline. We elected to bypass the La Grange processing plant to avoid unfavorable processing margins.

Average realized natural gas sales prices were $5.03 per MMBtu for the eleven months ended August 31, 2003 compared to $2.72 per MMBtu for the nine months ended September 30, 2002, an increase of $2.31 per MMBtu or 85.0%. In addition, average realized NGL sales prices were $0.41 per gallon for the eleven months ended August 31, 2003 compared to $0.32 per gallon for the nine months ended September 30, 2002, an increase of $0.09 per gallon or 28.1%.

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Transportation revenues were $41.5 million for the eleven months ended August 31, 2003. Our results for the nine months ended September 30, 2002 and for the 3 month period ended December 27, 2002 exclude revenues of Oasis Pipeline because our investment in Oasis Pipeline was treated as an equity method investment prior to December 27, 2002.

Cost of Sales. Total cost of sales was $901.5 million for the eleven months ended August 31, 2003 compared to $880.1 million for the nine months ended September 30, 2002, an increase of $21.4 million or 2.4%. Midstream cost of sales was $899.4 million for the eleven months ended August 31, 2003 compared to $880.1 million for the nine months ended September 30, 2002, an increase of $19.3 million or 2.3%. The increase is primarily due to the difference in the number of operating periods. The Transportation segment sold excess inventory during the eleven months ended August 31, 2003 resulting in a cost of sales of $2.1 million. The Transportation segment only periodically engages in activities that generate cost of sales.

Operating Expenses. Operating expenses were $28.0 million for the eleven months ended August 31, 2003 compared to $12.7 million for the nine months ended September 30, 2002, an increase of $15.3 million. This increase was due to the inclusion of approximately $4.9 million of operating expenses associated with Oasis Pipeline subsequent to December 27, 2002 and an additional two months of operations accounted for during the 2003 reporting period compared to the 2002 reporting period. Oasis Pipeline s operating expenses were not included in Aquila Gas Pipeline s results for the nine month period ended September 30, 2002, because Aquila Gas Pipeline accounted for its investment in Oasis Pipe Line under the equity method.

General and Administrative Expenses. General and administrative expenses were $16.0 million for the 11 months ended August 31, 2003 compared to $9.6 million for the nine months ended September 30, 2002, an increase of $6.4 million or 66.7%. On an annualized basis this represents a 36.4% increase. This annualized increase resulted primarily from higher employee bonuses and increased travel and insurance costs as well as the inclusion of general and administrative expense of Oasis Pipe Line subsequent to December 27, 2002.

Depreciation and Amortization. Depreciation and amortization expense was $13.5 million for the eleven months ended August 31, 2003 compared to $22.9 million for the nine months ended September 30, 2002, a decrease of $9.4 million or 41.0%. Depreciation and amortization expense decreased for the eleven months ended August 31, 2003 primarily due to the acquisition of midstream assets from Aquila Gas Pipeline, which resulted in a reduction in the depreciable basis on which these assets are depreciated. In addition, Aquila Gas Pipeline amortized $2.4 million during the nine months ended September 30, 2002 related to a transportation rights contract that has expired. This decrease was partially offset by the inclusion of $2.8 million of depreciation and amortization expense of Oasis Pipe Line subsequent to December 27, 2002.

Unrealized/Realized Loss on Derivatives. The unrealized loss on derivatives was $3.0 million for the eleven months ended August 31, 2003 compared to $5.0 million for the nine months ended September 30, 2002. Derivative price changes worked to the detriment of Aquila Gas Pipeline during the nine months ended September 30, 2002.

Equity in Net Income of Affiliates. Equity in net income of affiliates was $1.4 million for the eleven months ended August 31, 2003 compared to $5.4 million for the nine months ended September 30, 2002, a decrease of $4.0 million or 74.1%. This decrease resulted from equity in net income of affiliates for the eleven months ended August 31, 2003 not reflecting any equity earnings associated with Oasis Pipe Line subsequent to December 27, 2002 while Oasis Pipeline s earnings were recognized under the equity method of accounting for the three months ended December 27, 2002 and the nine months ended September 30, 2002. Equity earnings from Oasis Pipeline included in total equity in net income (loss) of affiliates was $1.6 million and $5.4 million for the three months ended December 27, 2002 and nine months ended September 30, 2002, respectively.

Interest Expense, net. Interest expense was $12.1 million for the eleven months ended August 31, 2003 compared to $3.9 million for the nine months ended September 30, 2002, an increase of $8.2 million or 210.3%. The increase was primarily due to the increased borrowings used to finance the purchase of midstream assets from Aquila Gas Pipeline and Dow Hydrocarbons Resources, Inc.

Income Tax Expense. Income tax expense was $4.4 million for the eleven months ended August 31, 2003 compared to a benefit of $0.5 million for the nine months ended September 30, 2002. As a partnership, we are not subject to income taxes. However, Oasis Pipeline, is a corporation that is subject to income taxes at an effective rate of 35%. The benefit for the nine months ended September 30, 2002 was related to the operating results of Aquila Gas Pipeline, which is a corporation subject to income taxes.

Net Income. Net income for the eleven months ended August 31, 2003 was $46.6 million compared to $4.7 million for the nine months ended September 30, 2002, an increase of $41.9 million. The increase in net income was due to the reasons described above.

Analysis of Historical Results of Operations   Heritage

Amounts discussed below reflect 100% of the results of MP Energy Partnership. MP Energy Partnership is a Canadian general partnership in which Heritage owned a 60% interest. Because MP Energy Partnership is primarily engaged in lower-margin wholesale distribution, its contribution to Heritage s net income is not significant and the minority interest of this partnership not owned by Heritage is excluded from the EBITDA, as adjusted, calculation. All other financial information and operating data included in management s discussion and analysis of financial condition and results of operations includes references to the foreign wholesale results of MP Energy Partnership.

Fiscal Year Ended August 31, 2003 Compared to the Fiscal Year Ended August 31, 2002

Volume. Total retail gallons sold in fiscal year 2003 were 375.9 million, an increase of 46.3 million from the 329.6 million gallons sold in fiscal year 2002. Of the increase in volume, approximately 6.0 million gallons was attributable to the volume added through acquisitions and approximately 40.3 million gallons was attributable to more favorable weather conditions in 2003 in some of Heritage s areas of operations, offset by warmer than normal weather conditions in other areas of operations.

Heritage sold approximately 74.3 million wholesale gallons during fiscal year 2003 of which 15.3 million were domestic wholesale and 59.0 million were foreign wholesale. In fiscal year 2002, Heritage sold 16.8 million domestic wholesale gallons and 65.3 million foreign wholesale gallons. The 6.3 million gallon decrease in foreign wholesale volumes of MP Energy Partnership was primarily due to an exchange contract that was in effect during fiscal year 2002, which was not economical to renew during fiscal year 2003.

Revenues. Total revenues for fiscal year 2003 were $571.4 million, an increase of $109.1 million, as compared to $462.3 million in fiscal year 2002. Retail revenues for fiscal year 2003 were $463.4 million as compared to $365.3 million for fiscal year 2002, an increase of $98.1 million, of which $40.9 million was primarily due to higher selling prices, and $49.8 million was primarily due to the increase in gallons sold as a result of colder weather conditions, and $7.4 million was due to the increase in gallons sold by customer service locations added through acquisitions. Selling prices in all the reportable segments increased from last year in response to higher supply costs. Domestic wholesale revenues increased $0.7 million to $10.7 million, due to an increase of approximately $1.7 million related to higher selling prices, offset by a decrease of approximately $1.0 million related to a decrease in gallons sold. Foreign wholesale revenues were $36.6 million for fiscal year 2003 as compared to $31.2 million for fiscal year 2002, an increase of $5.4 million primarily due to an approximate $9.3 million increase related to higher selling prices offset by an approximate $3.9 million related to decreased volumes as described above. Net liquids marketing revenues increased from $0.5 million in fiscal year 2002 to $1.3 million in fiscal year 2003, primarily due to more favorable movement in product prices in the current fiscal year. Other domestic revenues increased by $4.1 million to $59.4 million for fiscal year 2003, compared to $55.3 million for fiscal year ended 2002 primarily as a result of acquisitions.

Cost of Products Sold. Total cost of sales increased $58.9 million to $297.1 million as compared to $238.2 million for fiscal year 2002. Retail fuel cost of sales increased $51.7 million to $236.3 million for fiscal year 2003, of which approximately $29.1 million was due to increased volumes, and approximately $22.6 million was due to higher supply costs. U.S. wholesale cost of sales decreased $0.1 million to $9.6 million. Foreign wholesale cost of sales increased $4.7 million to $34.0 million, of which approximately $8.4 million was due to increased product costs this fiscal year, offset by an approximate decrease of $3.7 million attributable to the decreased volumes described above. Other cost of sales increased $2.6 million to $17.2 million for fiscal year 2003 primarily due to acquisitions.

Gross Profit. Total gross profit increased to $274.3 million in fiscal year 2003 as compared to $224.1 million in fiscal year 2002, due to the aforementioned increases in volumes and revenues described above, and the results of acquisitions, offset in part by the increases in product costs. For fiscal year 2003, retail fuel gross profit was $227.1 million, domestic wholesale fuel gross profit was $1.1 million, liquids marketing gross profit was $1.3 million, other gross profit was $42.2 million, and foreign wholesale gross profit was $2.6 million. As a comparison, for fiscal year 2002, Heritage recorded retail fuel gross profit of $180.7 million, domestic wholesale fuel gross profit of $0.3 million, liquids marketing gross profit of $0.5 million, other gross profit of $40.6 million, and foreign wholesale gross profit of $2.0 million.

Operating Expenses. Operating expenses were $152.1 million for fiscal year 2003 as compared to $133.2 million for fiscal year 2002. The increase of $18.9 million is primarily the result of $6.8 million of additional operating expenses incurred for employee wages and benefits related to the growth of Heritage from acquisitions made during fiscal year 2002, an increase of $5.5 million in the performance-based compensation plan expense due to higher operating performance, an increase of approximately $5.5 million in operating expenses in certain areas of the Partnership s operations due to acquisitions and to accommodate increased winter demand, and industry-wide increases in business insurance costs of $1.1 million.

Selling, General and Administrative. Selling, general and administrative expenses were $14.0 million for fiscal year 2003 as compared to $13.0 million for fiscal year 2002. This increase is primarily related to the performance-based compensation plan expense in 2003 that was not incurred in 2002, offset by a $0.7 million decrease in deferred compensation expense related to the adoption of FASB Statement No. 123 Accounting for Stock-Based Compensation (SFAS 123).

Depreciation and Amortization. Depreciation and amortization for fiscal year 2003 was $37.9 million, an increase of $0.9 million as compared to $37.0 million in fiscal year 2002. The increase is attributable to current year acquisitions.

Operating Income. Heritage reported operating income of $70.2 million in fiscal year 2003 as compared to the operating income of $41.0 million for fiscal year 2002. This increase is a combination of increased gross profit and a $0.7 million increase due to the adoption of SFAS 123, offset by increased operating expenses described above.

Interest Expense. Interest expense for fiscal year 2003 was $35.7 million, a decrease of $1.6 million as compared to $37.3 million in fiscal year 2002. The decrease was primarily attributable to the retirement of a portion of outstanding debt during the year.

Other Expense. Other expense for fiscal year 2003 was $3.2 million, an increase of $2.9 million as compared to $0.3 million in fiscal year 2002. The increase was primarily attributable to the reclassification into earnings of a $2.8 million loss on marketable securities in fiscal year 2003 that was previously recorded as accumulated other comprehensive loss on the balance sheet.

Taxes. Taxes for the year ended August 31, 2003 were $1.0 million due to the tax expense incurred by Heritage s corporate subsidiaries and other franchise taxes owed. Of the $1.0 million increase, $0.3 million was incurred in connection with the liquidation of Guilford Gas Service, Inc. during the fiscal year ended August 31, 2003. There was no tax expense for these subsidiaries for the year ended August 31, 2002.

Net Income. Heritage reported net income of $31.1 million, or $1.79 per limited partner unit, for fiscal year 2003, an increase of $26.2 million from net income of $4.9 million for fiscal year 2002. The increase is primarily the result of the increase in operating income, which includes a $0.7 million decrease in expenses due to the adoption of SFAS 123, partially offset by the increase in other expenses and taxes described above.

EBITDA, as adjusted. EBITDA, as adjusted, increased $29.5 million to $111.0 million for fiscal year 2003, as compared to EBITDA, as adjusted, of $81.5 million for fiscal year 2002. This increase is due to the operating conditions described above and is a record level of EBITDA, as adjusted, for the fiscal year results of Heritage. Please read footnote (e) under Item 6. Selected Historical Financial and Operating Data and Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Description of Indebtedness for a more detailed discussion of EBITDA, as adjusted.

Liquidity and Capital Resources

Our ability to satisfy our obligations will depend on its 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 includes capital expenditures made to connect additional wells to the our natural gas systems in order to maintain or increase throughput on existing assets 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;

growth capital expenditures, mainly for customer propane tanks and constructing new pipelines, processing plants and treating plants; and

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

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

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

growth capital expenditures will be financed by the proceeds of borrowings under the existing credit facilities; 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 an transportation 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.

Operating Activities. Cash provided by operating activities during the year ended August 31, 2004, was $162.7 million as compared to cash provided by operating activities of $70.9 million for the eleven months ended August 31, 2003. The net cash provided by operations for the year ended August 31, 2004 consisted of net income of $99.2 million, non-cash charges of $52.6 million, principally depreciation and amortization, and an increase in working capital of $10.9 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 operations, and the Energy Transfer Transactions.

Investing Activities. Cash used in investing activities during the year ended August 31, 2004 of $790.7 million is comprised of cash paid for acquisitions of $681.8 million and $109.7 million invested for maintenance and growth capital expenditures needed to sustain operations at current levels and to support growth of operations. Cash used in investing activities also includes proceeds from the sale of idle property of $1.1 million. The cash paid for acquisitions included $166.6 million of cash paid in the Energy Transfer Transactions including $100 million for the purchase of Heritage Holdings, $16.7 million expended for retail propane acquisitions, and $498.5 million expended for the ET

Fuel System. Heritage expended $22.5 million of cash for acquisitions of retail propane operations for the period ended January 19, 2004, issued $17.9 million of Common Units and $2.4 million of non-competes and assumed $3.8 of liabilities in connection with these acquisitions.

Financing Activities. Cash received from financing activities during the year ended August 31, 2004 was $656.7 million. ETC OLP borrowed $325.0 million under the Term Loan Facility and the proceeds were used to retire $218.5 million of debt outstanding at the time of the Energy Transfer Transactions, satisfy ETC OLP s accounts payable and other specified liabilities as they became due, and fund certain other expenses in connection with the Energy Transfer Transactions. In conjunction with the amendment to the Term Loan Facility on June 2, 2004, ETC OLP borrowed an additional $400.0 million to partially finance the purchase of the ET Fuel System. The cash received from financing activities is net of $8.2 million in debt issuance costs. The net decrease in HOLP s Bank Facility was $79.9 million since the Energy Transfer Transactions, and $35.1 million was used for principal payments on HOLP s notes and other long-term debt. We raised $528.1 million of net proceeds through the sale of 9,200,000 million Common Units at an offering price of $38.69 per unit in January 2004 and a Secondary Offering of 4,500,000 million Common Units at an offering price of $39.20 per unit on June 30, 2004, including an over-allotment option at the offering price of $39.20 per unit for 675,000 exercised on July 2, 2004. Proceeds of $334.3 million from the January 2004 offering were used to finance the Energy Transfer Transactions and for general partnership purposes, including a total distribution of $205.7 million to La Grange Energy in connection with the terms of the Energy Transfer Transactions. The net proceeds of $193.8 million from our Secondary Offering and the exercise of the over-allotment were used to repay a portion of the outstanding indebtedness incurred to fund the ET Fuel System and for general partnership purposes. Cash received from financing activities includes the General Partner s contributions of $22.2 million to maintain their 2% General Partners interest and is reduced by the distributions we paid to our Common and Class D Unitholders and the General Partners 2% interest of $63.4 million.

Financing and Sources of Liquidity

We maintain separate credit facilities for each of ETC OLP and HOLP. Each credit facility is secured only by the assets of the operating partnership that it finances, and neither operating partnership nor its subsidiaries will guarantee the debt of the other operating partnership.

Energy Transfer Facilities

ETC OLP has a $725.0 million Term Loan Facility that matures on January 18, 2008. Amounts borrowed under the ETC OLP Credit Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The Term Loan Facility is secured by substantially all of the ETC OLP s assets. On June 1, 2004, the Term Loan Facility was amended to increase the borrowing capacity from $325.0 million to $725.0 million. On June 2, 2004, ETC OLP borrowed an additional $400.0 million to partially finance the purchase of the midstream natural gas assets of TXU Fuel Company. As of August 31, 2004, the Term Loan Facility had a balance of $725.0 million with a weighted average interest rate of 4.45%.

A $225.0 million Revolving Credit Facility is available through January 18, 2008. Amounts borrowed under the ETC OLP Credit Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The maximum commitment fee payable on the unused portion of the facility is 0.50%. The facility is fully secured by substantially all of ETC OLP s assets. As of August 31, 2004, there were no amounts outstanding under the Revolving Credit Facility, and $4.7 million in letters of credit outstanding, which reduce the amount available for borrowing under the Revolving Credit Facility. Letters of Credit under the Revolving Credit Facility may not exceed $40.0 million. On June 1, 2004, the Revolving Credit Facility was amended to increase the borrowing capacity from $175.0 million to $225.0 million. On June 2, 2004 ETC OLP borrowed $105.0 million under the Revolving Credit Facility to partially finance the purchase of the midstream natural gas assets of TXU Fuel Company. On July 6, 2004, ETC OLP repaid the amount borrowed on the Revolving Credit Facility and as of August 31, 2004 there were no amounts outstanding under the Revolving Credit Facility.

HOLP Facilities

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. 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 3.2038% for the amount outstanding at August 31, 2004. The maximum commitment fee payable on the unused portion of the facility is 0.50%. 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. All receivables, contracts, equipment, inventory, general intangibles, cash concentration accounts, and the capital stock of HOLP s subsidiaries secure the Senior Revolving Working Capital Facility. As of August 31, 2004, the Senior Revolving Working Capital Facility had a balance outstanding of $24.6 million and $1.0 million of outstanding letters of credit. 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. Letter of Credit Exposure plus the Working Capital Loan cannot exceed the $75.0 million maximum Working Capital Facility.

The Third Amended and Restated Credit Agreement also includes a $75.0 million 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 3.2038% for the amount outstanding at August 31, 2004. 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, and the capital stock of HOLP s subsidiaries secure the Senior Revolving Acquisition Facility. As of August 31, 2004, the Senior Revolving Acquisition Facility had a balance outstanding of $23.0 million.

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 its 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 paid all quarterly distributions since its inception in 1996 up to and including the quarterly distribution of $0.65 per unit paid on January 14, 2004. Heritage had raised its quarterly distribution over the years from $0.50 per unit in 1996 to $0.65 per unit as of the quarterly distribution paid on January 14, 2004. On April 14, 2004, we paid a quarterly distribution of $0.70 per unit, or $2.80 per unit annually, to the Unitholders of record at the close of business on April 2, 2004. On June 17, 2004, we announced that we raised the quarterly distribution to $0.75 per unit (an annualized rate of $3.00) an increase of $0.05 per unit (an annualized increase of $0.20 per unit) to the Unitholders of record as of July 2, 2004. On September 20, 2004, we announced another increase to our quarterly distribution, raising it to $0.825 per unit, or $3.30 per unit annually. This distribution represented an increase of $0.075 per unit (an annualized increase of $0.30 per unit) over the distribution paid for the third quarter of fiscal 2004. The distribution was payable on October 15, 2004 to Unitholders of record as of the close of business on October 7, 2004. The current distribution includes incentive distributions payable to the General Partner to the extent the quarterly distribution exceeds $0.55 per unit (an annualized rate of $2.20).

Description of Indebtedness

In connection with its initial public offering, on June 25, 1996, Heritage entered into a Note Purchase Agreement whereby Heritage issued $120 million principal amount of 8.55% Senior Secured Notes (the Notes) with institutional investors. Interest is payable semi-annually in arrears on each December 31 and June 30. The 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, 2004, $84 million of principal debt was outstanding under the Senior Secured Notes.

On November 19, 1997, Heritage entered into a Note Purchase Agreement (Medium Term Note Program) that provided for the issuance of up to $100 million of senior secured promissory notes 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 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 Acquisition Facility. No future placements are permitted under the unused portion of the 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, 2004, $31.8 million of principal debt was outstanding under the Medium Term Note Program.

On August 10, 2000, Heritage entered into a Note Purchase Agreement (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, Heritage 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%. Heritage used the net proceeds from the Senior Secured Promissory Notes to repay the balance outstanding under the Acquisition Facility and to reduce other debt. Interest is payable quarterly. During the fiscal year ended August 31, 2003, Heritage 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, 2004, $208.2 million of principal debt was outstanding under the Senior Secured Promissory Notes.

The Note Agreements for each of the Senior Secured Notes, Medium Term Note Program and Senior Secured Promissory Notes, and the Operating Partnership s bank credit facilities contain customary restrictive covenants applicable to the Operating Partnerships, changes in ownership of the Operating Partnerships, including limitations on the level of additional indebtedness, creation of liens, and substantial disposition of assets. These covenants require the Operating Partnerships 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 for HOLP s bank credit facility and Note Agreements and 4.75 to 1.0 during the 365-day period following the funding of the purchase price of the ET Fuel System and to 4.00 to 1.00 during any period other than the 365-day period following the funding of the purchase price of the ET Fuel System for ETC OLP s bank credit facility 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 for HOLP s bank credit facility and Note Agreements and 2.75 to 1 for ETC OLP s bank credit facility. 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 Operating Partnership 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 debt agreements also provide that the Operating Partnerships may declare, make, or incur a liability to make, a restricted 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 with respect to the immediately preceding quarter; (b) no default or event of default exists before such restricted payment; and (c) each Operating Partnership s restricted payment is not greater than the product of each Operating Partnership s Percentage of 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. 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 the Operating Partnership 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 was in compliance or had no continuing defaults 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, 2004. 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. On April 18, 2004 the Notes were rated investment grade or better thereby alleviating the requirement that we pay the additional 1% interest. All of the ETC OLP assets secure the bank credit facilities of ETC OLP.

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The following table summarizes our long-term debt and other contractual obligations as of August 31, 2004:

In thousands	Payments Due by Period				
Contractual Obligations	**Total**	**Less Than 1 Year**	**1 3 Years**	**3 5 Years**	**More Than 5 Years**
Long-term debt	$1,101,828	$30,957	$111,077	$813,665	$146,129
Interest on long-term debt (a)	257,463	60,377	110,060	46,946	40,080
Operating lease obligations	13,437	4,794	5,152	2,863	628
Totals	$1,372,728	$96,128	$226,289	$863,474	$186,837

(a) Interest expense includes fixed rate debt on the assumed outstanding principal and interest on variable rate debt at the current interest rates on the bank credit facilities. See Note 5 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

In January of 2003, the Financial Accounting Standards Board (FASB) issued Financial Interpretation No. 46 *Consolidation of Variable Interest Entities An Interpretation of ARB No. 51* (FIN 46). In December 2003, the FASB issued FIN 46R, which clarified certain issues identified in FIN 46. FIN 46R requires an entity to consolidate a variable interest entity to consolidate a variable interest entity if it is designated as the primary beneficiary of that entity even if the entity does not have a majority of voting interest. A variable interest entity is generally defined as an entity where its equity is unable to finance its activities or where the owners of the entity lack the risk and rewards of ownership. The provisions of this statement apply at inception of any entity created after January 31, 2003. For an entity created before February 1, 2003, the provisions of this interpretation must be applied at the beginning of the first interim or annual period beginning after March 15, 2004. The adoption did not have an impact on the Partnerships consolidated financial position or results of operations.

As of August 31, 2004, we own various unconsolidated entities in which our share of the unconsolidated entities range from 49% to 50%. We account for our investments under the equity method of accounting as prescribed by APB Opinion No. 18, *The Equity Method of Accounting for Investments in Common Stock*. We do not control these entities and each partner shares in all profits and losses equal to their respective share in the entities. There are no limits on the exposure to losses or on the ability to share in returns. Based on the analysis performed, we are not the primary beneficiary of the entities, and as a result, we will not consolidate the entities but will continue to account for our investment in these entities under the equity method.

In May 2003, the FASB issued Statement No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity* (SFAS 150). SFAS 150 establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. It requires that an issuer classify a financial instrument that is within the scope of SFAS 150 as a liability (or an asset in some circumstances). This statement is effective for financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. We adopted the provisions of

SFAS 150 as of September 1, 2003. The adoption did not have a material impact on the Partnership s consolidated financial position or results of operations.

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. We recognize revenue for sales or services at the time the natural gas or NGLs are delivered or at the time the service is performed. Transportation capacity payments are recognized when earned in the period the capacity is made available. Sales of propane, propane appliances, parts, and fitting 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 is recognized upon completion of the service and tank rent is recognized ratably over the period it is earned. Shipping and handling revenues are included in the price of propane charged to customers, and thus are classified as revenues.

Marketable Securities. We have marketable securities that are classified as available-for-sale. Unrealized holding losses occur as a result of declines in the market value of our holdings. The fair market value of these holdings is determined based upon the market price of the securities, which are publicly traded securities. Based on the performance of the securities over the preceding nine-month period, we reviewed the fair market value to determine if an other-than temporary impairment should be recorded.

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

Amortization of Intangible Assets. 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. These contracts consist primarily of commodity forward, future, swaps, options and certain basis contracts as cash flow hedging instruments. Many of these 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 instrument 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. The values have been adjusted to reflect the potential impact of liquidating a position in an orderly manner over a reasonable period of time under existing market conditions. 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 Imbalances. We record imbalance 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 imbalances 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 $6.1 million as of August 31, 2004, a change in natural gas prices of 10 percent could positively or negatively affect our results of operations by $0.6 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.

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, processing and marketing activities. Derivative instruments are used to protect margins on natural gas purchases, sales, transportation, and natural gas liquid sales. Pursuant to our risk management policy, we do not engage in speculative trading in our midstream, processing and marketing activities. 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.

We use a combination of financial instruments including, but not limited to, futures, price swaps 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 requiring market purchases to meet commitments, or (2) our counterparties fail to purchase the contracted quantities of natural gas or otherwise fail to perform. To the extent that we engage in hedging activities we may be prevented from realizing the benefits of favorable price changes in the physical market. However, we are similarly protected against decreases in such prices.

We manage our price risk related to future physical purchase or sale commitments for our producer services activities by entering into either corresponding physical delivery contracts or financial instruments with an objective to balance our future commitments and significantly reduce our risk to the movement in 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 No. 133.

In our midstream and transportation segments, we account for certain of our derivatives as cash flow hedges under SFAS 133. This accounting allows for the effective portion of gains and losses on derivatives of cash flow hedges to be reported as other comprehensive income. The ineffective portion of the hedge will be reported in net income as it occurs. When the derivative is settled, along with the hedged transaction, the amount in other comprehensive income that is related to the derivative will be reported in net income.

For each reporting period, we record the fair value of financial instruments based on the difference between the quoted market price and the contract price. Accordingly, the change in fair value is recorded as a liability or asset. In addition, realized gains or losses from settled contracts are recorded in gain or loss from derivates. The effective portion of changes in the fair value of cash flow hedges is recorded in accumulated other comprehensive income until the related anticipated future cash flow is recognized in earnings.

The following summarizes our open commodity derivative positions as of August 31, 2004. Our counterparties to financial contracts include ABN Amro, BP Corporation, Sempra Energy Trading Corp., and Entergy-Koch Trading, LP.

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	Commodity	Notional Volume MMBTU	Maturity	Fair Value
Basis Swaps IFERC/Nymex	Gas	54,472,500	2004-2005	$ 1,451
Basis Swaps IFERC/Nymex	Gas	62,767,500	2004-2005	592
				$ 2,043
Swing Swaps IFERC	Gas	119,495,000	2004-2005	$ 704
Swing Swaps IFERC	Gas	45,265,000	2004-2005	(399)
Swing Swaps IFERC	Gas	76,720,000	2006-2008	
				$ 305
Futures Nymex	Gas	10,057,500	2004-2005	$(1,311)
Futures Nymex	Gas	12,677,500	2004-2005	2,941
				$ 1,630
		Barrels		
NGL Swaps	Condensate, Propane & Ethane	250,000	2004-2005	$ (86)

We also enter into energy trading contracts, which are not derivatives, and therefore are not within the scope of SFAS 133. EITF Issue No. 98-10, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities* (EITF 98-10), applied to energy trading contracts not within the scope of SFAS 133 that were entered into prior to October 25, 2002. The types of contracts we utilize in our liquids marketing segment include energy commodity forward contracts, options, and swaps traded on the over-the-counter financial markets. In accordance with the provisions of SFAS 133, derivative financial instruments utilized in connection with our liquids marketing activity are accounted for using the mark-to-market method. Additionally, all energy-trading contracts entered into prior to October 25, 2002 were accounted for using the mark-to-market method in accordance with the provisions of EITF 98-10 by Heritage. Under the mark-to-market method of accounting, forwards, swaps, options, and storage contracts are reflected at fair value, and are shown in the consolidated balance sheet as assets and liabilities from liquids marketing activities. As of August 31, 2002, Heritage adopted 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 statement of operations as liquids marketing revenue. Changes in the assets and liabilities from the liquids marketing activities result primarily from changes in the market prices, newly originated transactions, and the timing and settlement of contracts. EITF 02-3 also rescinds EITF 98-10 for all energy trading contracts entered into after October 25, 2002 and specifies certain disclosure requirements. Consequently, we do not and Heritage did not apply mark-to-market accounting for any contracts entered into after October 25, 2002 that are not within the scope of SFAS 133. We attempt to balance its contractual portfolio in terms of notional amounts and timing of performance and delivery obligations. However, net unbalanced positions can exist.

The notional amounts and terms of these financial instruments as of August 31, 2004 include fixed price payor for 345,000 barrels of propane and fixed price receiver of 345,000 barrels of propane. Notional amounts reflect the volume of the transactions, but do not represent the amounts exchanged by the parties to the financial instruments. Accordingly, notional amounts do not accurately measure Heritage s exposure to market or credit risks.

The fair value of the financial instruments related to liquids marketing activities, as of August 31, 2004 were assets of $1.5 million and liabilities of $1.2 million.

On all transactions where we are exposed to counterparty risk, we analyze the counterparty s financial condition prior to entering into an agreement, establish limits, and monitor the appropriateness of these limits on an ongoing basis.

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Sensitivity analysis

At August 31, 2004, the fair value of Nymex futures was $1.6 million on a net short position of 2,620,000 MMBtu. A hypothetical change of 10% in the underlying commodity value would change the fair value of the futures by $1.1 million.

At August 31, 2004 the fair value of basis trades was $2.0 million on a net short of position of 8,295,000 MMBtu. A hypothetical change of 10% in basis prices would change the fair value by $0.4 million.

We also hedged liquid sales in our midstream segment during the quarter ended August 31, 2004. The fair value of these hedges at August 31, 2004 was $0.1 million on a short position of 250,000 Bbls. A hypothetical price change of 10% on the liquid hedges would have an effect of $0.9 million on the fair value of derivatives.

Estimates related to our liquids marketing activities are sensitive to uncertainty and volatility inherent in the energy commodities markets and actual results could differ from these estimates. A theoretical change of 10% in the underlying commodity value of the liquids marketing contracts would not change the market value of the contracts as there was no unbalanced positions at August 31, 2004.

The following table summarizes the fair value of our liquids marketing contracts, aggregated by method of estimating fair value of the contracts as of August 31, 2004 where settlement had not yet occurred. These contracts all have a maturity of less than 1 year. The market prices used to value these transactions reflect management s best estimate considering various factors including closing average spot prices for the current and outer months plus a differential to consider time value and storage costs.

Source of Fair Value	August 31, 2004	Heritage August 31, 2003
Prices actively quoted	$ 609	$ 80
Prices based on other valuation methods	902	3
Assets from liquids marketing	$1,511	$ 83
Prices actively quoted	$ 569	$ 80
Prices based on other valuation methods	656	
Liabilities from liquids marketing	$1,225	$ 80
Unrealized gains	$ 286	$ 3

The following table summarizes the changes in the unrealized fair value of our liquids marketing contracts where settlement had not yet occurred for the fiscal year ended August 31, 2004 and for Heritage for the fiscal years ended 2003 and 2002.

		Heritage	
	August 31, 2004	**August 31, 2003**	**August 31, 2002**
Unrealized gains (losses) in fair value of contracts outstanding at the beginning of the period	$	$483	$ (665)
Unrealized gains (losses) recognized at inception of contracts			
Unrealized gains (losses) recognized as a result of changes in valuation techniques and assumptions			
Other unrealized gains (losses) recognized during the period	1,286	850	1,207

		Heritage	
	August 31, 2004	August 31, 2003	August 31, 2002
Less: Realized gains (losses) recognized during the period	1,000	1,330	59
Unrealized gains (losses) in fair value of contracts outstanding at the end of the period	$ 286	$ 3	$483

Interest Rate Risk

We are exposed to changes in interest rates, primarily as a result of our long-term debt with floating interest rates. An interest rate swap agreement is used to manage a portion of the exposure related to ETC OLP s Term Loan Facility to changing interest rates by converting floating rate debt to fixed rate debt. As of August 31, 2004, this interest rate swap had a notional amount of $75 million that matures on October 9, 2005. The fair value of the interest rate swap is marked to market and the changes in the fair value are recorded in interest expense. The fair value of the interest rate swap was a liability of $0.5 million as of August 31, 2004. We also have long-term debt instruments, which are typically issued at fixed interest rates. 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.

As of August 31, 2004, we had $772.6 million of variable rate debt of which $75.0 million is covered by the interest rate swap discussed above. A change of one percent in the LIBOR rates effective as of August 31, 2004 would have changed interest expense by $7.0 million. This amount has been determined by considering the impact of the hypothetical interest rates on our variable rate borrowings outstanding as of August 31, 2004.

Credit risk

We are diligent in attempting to ensure that we issue credit to only credit-worthy customers. However, our purchase and resale of gas exposes us to significant credit risk, as the margin on any sale is generally a small percentage of the total sales price. Therefore, a credit loss can be very large relative to our overall profitability.

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 for the current 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 were: (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.

We have provided Ernst & Young LLP with a copy of the foregoing disclosure. Attached as Exhibit 16 to a

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previously filed Form 8-K is a copy of Ernst & Young LLP s letter, dated February 4, 2004, stating its agreement with such statements.

Both Ernst & Young LLP and Grant Thornton LLP were engaged in discussions with respect to the preparation of the pro forma financial statements that were required in connection with the series of transactions described above.

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 Chief Executive Officers 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 Chief Executive Officers of our General Partner, concluded that our disclosure controls and procedures were adequate and effective as of August 31, 2004.

During fiscal year 2004, we began the implementation of a new accounting software system for our propane operations. In response to requirements associated with the implementation of this system and the transition from the prior system, certain changes were made to our internal controls over financial reporting. These changes were primarily made during the quarter ended May 31, 2004. Management continues to monitor these changes and have also continued the ongoing process of routinely reviewing and evaluating our internal controls over financial reporting. Based on that review and evaluation, management believes our disclosure controls and procedures were effective in enabling us to record, process, summarize and report the information required to be included in this annual report within the required time period.

There have been no other changes in our internal controls over financial reporting (as defined in Rule 13(a) 15 or Rule 15d 15(f) of the Exchange Act) or in other factors during the fiscal year covered by this report that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting, and there have been no corrective actions with respect to significant deficiencies and material weaknesses in our internal controls.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT.

Partnership Management

In February 2002, our Common Unitholders approved the substitution of U.S. Propane, L.P. (the General Partner) as General Partner of the Partnership. The General Partner manages and directs all of the Partnership s activities. The activities of the General Partner are managed and directed by its general partner, U.S. Propane, L.L.C. (USP LLC). Our officers and directors are officers and directors of USP LLC. The owners of the General

Partner and USP LLC appointed thirteen members, individually, each a manager of USP LLC, to USP LLC s Board of Directors. Collectively, these thirteen persons are referred to as our Board of Directors. Since February 2002 through January 2004, the Board of Directors has been comprised of its Chairman, its President and Chief Executive Officer, two persons designated by each of the four member/owners of USP LLC, and three independent persons approved by a majority of the member/owners.

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 USP LLC to La Grange Energy, L.P. (the General Partner Transaction). The eight members of the Board of Directors that had been previously designated by the four member/owners of USP LLC and the former Chairman resigned at the time of the General Partner Transaction. The three independent members and USP LLC s President remained on the Board of Directors, and additional members were elected to the Board of Directors by La Grange Energy, L.P. Currently, USP LLC s Board of Directors is comprised of its two Co-Chairmen, USP 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.

Independent Committee

The Board of Directors appoints members of the Board to serve on the Independent Committee with the authority to review specific matters to 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 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.

Audit Committee

The Board of Directors has established an Audit Committee in accordance with Section 3(a)(58)(A) of the Securities Exchange Act of 1934, as amended. The Board of Directors appoints persons who are independent under the NYSE s standards for audit committee members to serve on its Audit Committee. The Board has determined that based on relevant experience, Audit Committee member Stephen L. Cropper qualifies as an Audit Committee financial expert. A description of Mr. Cropper s qualifications 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 as the

Audit Committee in October 2004.

Compensation Committee

Although we are not required under NYSE rules to appoint a Compensation and Nominating Committee because we are a limited partnership, the Board of Directors of USP 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. Mr. Turner is the Chairman of the Compensation Committee.

Code of Ethics

The Board of Directors has adopted a Code of Ethics 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 Ethics can be viewed on our website at www.energytransfer.com. Amendments to, or waivers from, the Code of Ethics 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 Ethics 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 the Partnership s website in general is intended or deemed to be incorporated by reference herein.

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 31, 2004. Executive officers and directors are elected for one-year terms.

Name	Age	Position with General Partner
Ray C. Davis	62	Co-Chief Executive Officer and Co-Chairman of the Board of Directors of the General Partner
Kelcy L. Warren	48	Co-Chief Executive Officer and Co-Chairman of the Board of Directors of the General Partner
H. Michael Krimbill	51	President, Chief Financial Officer and Director of the General Partner
R.C. Mills	67	Executive Vice President and Chief Operating Officer
Mackie McCrea	45	Senior Vice President Commercial Development
Bradley K. Atkinson	49	Vice President Corporate Development
Robert A. Burk	47	Vice President and General Counsel and Secretary
John W. Daigh (1)	49	Vice President and Treasurer
Karen Z. Hicks (2)	42	Vice President of Administration and Controller
Stephen L. Cropper	54	Director of the General Partner

Bill W. Byrne	74	Director of the General Partner
J. Charles Sawyer	68	Director of the General Partner
David R. Albin	45	Director of the General Partner
Kenneth A. Hersh	41	Director of the General Partner

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Name	Age	Position with General Partner
Paul E. Glaske	71	Director of the General Partner
K. Rick Turner	46	Director of the General Partner
Ted Collins, Jr.	66	Director of the General Partner
John W. McReynolds	53	Director of the General Partner

(1) Elected Vice President and Treasurer September 2004.

(2) Elected Vice President of Administration September 2004.

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 operations of Energy Transfer and Heritage Propane in January 2004. Mr. Davis also serves as Co-Chief Executive Officer of the general partner of ETC OLP, and as Co-Chief Executive Officer and Co-Chairman of the Board of the general partner of La Grange Energy, positions he has held since their formation in 2002. Prior to the combination of the operations of Energy Transfer and Heritage Propane, Mr. Davis served as Vice President of the general partner of ET Company I, Ltd., the entity that operated Energy Transfer 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 operations of Energy Transfer and Heritage Propane in January 2004. Mr. Warren also serves as Co-Chief Executive Officer of the general partner of ETC OLP, and as Co-Chief Executive Officer and Co-Chairman of the Board of the general partner of La Grange Energy, positions he has held since their formation in 2002. Prior to the combination of the operations of Energy Transfer and Heritage Propane, 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 is also a director of our General Partner. 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 from March 2000 to January 2004. Mr. Krimbill has served as a director of our General Partner since his election in August 2000. Prior to joining Heritage, Mr. Krimbill was the Treasurer of a publicly traded, fully integrated oil company.

R.C. Mills. Mr. Mills is the Executive Vice President and Chief Operating Officer of our General Partner. 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 and its successor, Suburban Propane, Inc. At the time he left Suburban in 1991, Mr. Mills was Vice President of Supply and Wholesale.

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 Energy Transfer and Heritage Propane in January 2004. Prior to the combination of the operations of Energy Transfer and Heritage Propane, 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 Energy Transfer, Mr. Burk was a partner in the law firm of Doerner, Sanders, Daniel & Anderson, LLP, which served as outside counsel to Heritage Propane since going public 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 Energy Transfer 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 Energy Transfer 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 16 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 3 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.

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 has served as a director of or General Partner since 1991 and is a member of both the Independent Committee and the Audit Committee. Mr. Sawyer is a former president and director of the NPGA.

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. 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. 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 has been a principal of Stephens, Inc., one of the largest off-Wall Street investment banking groups, since 1990. Prior to joining Stephens in 1983, Mr. Turner was employed with Peat, Marwick, Mitchell & Company. Mr. Turner s areas of focus include oil and gas exploration, natural gas gathering and processing industries, and power technology. He currently serves as a director of Atlantic Oil Corporation; SmartSignal Corporation; Neucoll, Inc.; Jebco Seismic, LLC; and North American Energy Partners. Mr. Turner has served as a director of our General Partner since February 2004 and is a member of the Compensation Committee.

Ted Collins, Jr. Mr. Collins is an independent oil and gas producer. 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 Partner in the Dallas law office of Hunton & Williams. Mr. McReynolds has been a practicing attorney with Hunton & Williams, and its predecessors, since beginning his career in 1978. Mr. McReynolds practice focuses on the energy industry and energy-related entities. Mr. McReynolds has served a director of our General Partner since August 2004.

Compensation of the General Partner

The General Partner does not receive any management fee or other compensation in connection with its management of the Partnership and the Operating Partnerships. The General Partner 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 General Partner has not incurred additional reimbursable costs since that time. Heritage incurred costs reimbursable to the General Partner of $108.9 million for the year ended August 31, 2003 and $95.7 million for the year ended August 31, 2002.

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

Section 16(a) of the Securities and Exchange Act of 1934 requires the Partnership s officers and directors, and persons who own more than 10% of a registered class of the Partnership s 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 Form 5s were required for those persons, we believe that during fiscal year ending August 31, 2004, 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 TAAP, LP and TAAP GP LLC, and a late Form 3 filing for Robert A. Burk.

ITEM 11. EXECUTIVE COMPENSATION.

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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 our General Partner during fiscal year 2004; (ii) the four next highly compensated executive officers other than the Chief Executive Officer, who served as executive officers of our General Partner during fiscal year 2004 and (iii) any persons who would have been reported had they been an executive officer of our General Partner at the end of fiscal year 2004.

Name and Principal Position	Year	Salary	Bonus (3)	Other Annual Compensation (4)	All Other Compensation (5)
Ray C. Davis	2004	$120,000	$	$ 172	$
Co-Chief Executive	2003				
Officer (1)	2002				
Kelcy L. Warren	2004	$120,000	$	$ 172	$
Co-Chief Executive	2003				
Officer (1)	2002				
H. Michael Krimbill	2004	$350,000	$609,000	$ 372	$1,321,240
President and Chief	2003	350,000	60,000	325	356,878
Financial Officer (2)	2002	350,000	350,000	242	
R. C. Mills	2004	$335,000	$594,000	$ 2,052	$1,321,240
Executive Vice President	2003	335,000	60,000	2,052	356,878
and Chief Operating Officer	2002	335,000	350,000	1,700	
Mackie McCrea	2004	$183,042	$248,000	$ 186	$
Senior Vice President	2003				
Commercial Development	2002				
Bradley K. Atkinson	2004	$220,000	$479,000	$ 165	$1,321,240
Vice President	2003	220,000	60,000	165	356,878
Corporate Development	2002	220,000	410,944	158	
Robert A. Burk (6)	2004	$200,000	$	$ 145	$
Vice President General	2003				
Counsel and Secretary	2002				
Michael L. Greenwood (7)	2004	$240,000	$499,000	$ 184	$1,024,756
Vice President and	2003	240,000		184	118,950
Chief Financial Officer	2002	240,000			
A. Dean Fuller (8)	2004	$205,755	$	$ 233	$
Senior Vice President	2003				
Operations	2002				

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

(2) Mr. Krimbill served as President and Chief Executive Officer of our General Partner until January 2004. After the transactions with ETC OLP, Mr. Krimbill was elected President and Chief Financial Officer of our General Partner.

(3) Bonuses are earned based on the results of operations for each fiscal year. Bonuses for the 2004 fiscal year for Messrs. Krimbill, Mills, Atkinson, and Greenwood also include payments for the termination of their employment contracts in connection with the Energy Transfer Transaction.

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(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 Transaction.

(6) Mr. Burk was named Vice President General Counsel of our General Partner in February of 2004. Mr. Burk s 2004 salary is annualized.

(7) Mr. Greenwood served as Vice President Finance of our General Partner following the Energy Transfer Transaction until his retirement in August of 2004. Mr. Greenwood s salary is annualized for the fiscal year 2002.

(8) Mr. Fuller served as Senior Vice-President Operations following the Energy Transfer Transaction until his retirement in August of 2004.

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 146,000 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 500 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 La Grange Energy 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. As of August 31, 2004, 8,296 Units have been awarded and have not yet vested. 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 8,296 Units previously awarded vest), and no additional grants 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 250,000 units and if targeted levels were achieved, a maximum of 500,000 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, 66,118 units vested pursuant to the vesting rights of the Long-Term Incentive Plan and Common Units were issued. In connection with the acquisition by La Grange Energy of our General Partner in January 2004, 150,018 units vested and Common Units were issued, and the Long-Term Incentive Plan terminated. Heritage recognized compensation expense of $0.6 million, $0.9 million, and $1.5 million for fiscal years 2004, 2003, and 2002, respectively.

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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 900,000 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 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. As of August 31, 2004, no grants of awards had been made to any employee under the 2004 Unit Plan. Subsequent to August 31, 2004, 129,600 awards of units were made under the 2004 Unit Plan to employees, including executive officers. 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 MLP 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 USP 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 20% 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, 2004, Initial Director s Grants totaling 4,000 units have been 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 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 stock appreciation right is exercised and the strike price; (iii) units; or (iv) any combination hereof. As of August 31, 2004, there has 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.

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 2004, 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.

In February 2004, the disinterested members of our Board of Directors, approved the payment to eligible directors of 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, 2004, regarding the beneficial ownership of the Partnership s 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 beneficially owning 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)		*
	Kelcy L. Warren (3)		*
	H. Michael Krimbill (4)	362,559	*
	Bill W. Byrne	78,157	*
	J. Charles Sawyer	68,657	*
	Stephen L. Cropper	7,500	*
	David R. Albin (5)		*
	Kenneth A. Hersh (5)		*
	Paul E. Glaske	10,000	*
	K. Rick Turner (5)		*
	Ted Collins, Jr.		*
	John McReynolds		*
	R.C. Mills (4)	368,009	*
	Mackie McCrea		*
	Bradley K. Atkinson	53,600	*
	Robert A. Burk		*
	Michael L. Greenwood (6)	61,111	*
	Dean A. Fuller (3) (6)		*
	All Directors and Executive Officers as a group (7) (19 persons)	985,181	2.21%
	La Grange Energy, L.P. (8)	15,883,234	35.58%
Class C Units	FHS Investments, L.L.C.	1,000,000	100%
Class E Units	Heritage Holdings, Inc. (9)	4,426,916	100%

* Less than one percent (1%)

(1) The address for La Grange Energy and Messrs. Davis and Warren is 2838 Woodside Street, Dallas, Texas 75204. The address for Heritage Holdings and Messrs. Krimbill, Atkinson, and Burk is 8801 S. Yale Avenue, Suite 310, Tulsa, Oklahoma 74137. 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 FHS Investments is 2215 B Renaissance Dr., Suite 5, Las Vegas, Nevada 89119.

(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, Warren, McCrea, and Fuller in La Grange Energy, L.P., they may be deemed to beneficially own the limited partnership interests held by La Grange Energy, L.P. to the extent of their respective interests therein. Any such deemed ownership is not reflected in the table.

(4) Each of Messrs. Mills 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 La Grange Energy, L.P. and may be deemed to beneficially own the limited partnership interest held by La Grange Energy, L.P., though such ownership is not depicted in the table.

(6) Messrs. Greenwood and Fuller retired from their respective offices prior to August 31, 2004.

(7) Includes persons who were not officers of our general partner at August 31, 2004 but included in the named executive officers table under Item 11, and includes persons who were named officers between September 1, 2004 and October 31, 2004.

(8) La Grange Energy, L.P. owns 95% all of the member interests of U.S. Propane, L.L.C. and 95% of the limited partner interests of U.S. Propane, L.P. U.S. Propane, L.L.C. is the General Partner of U.S. Propane, L.P. with a .01% general partner interest.

(9) Energy Transfer Partners, L.P. 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 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 reviewed by the Audit Committee, and are no less favorable than those available from other providers of compression services. During fiscal year 2004, payments totaling $279,000 were made to the ETG Entities for compression services provided to and utilized in our natural gas midstream operations.

One of our natural gas midstream subsidiaries owns 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 an entity in which one of our directors, Ted Collins, Jr. owns a 50% interest. We are the operator of the Dorado System. At August 31, 2004, there was a balance of $248,000 owing to us by this co-owner entity for services we provided as operator.

During the fiscal year ended August 31, 2004, payments of approximately $112,000 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, and for the representation of ETC OLP in ongoing matters. John W. McReynolds, a director of our General Partner since August 2004, is a partner in the Dallas, Texas office of Hunton & Williams.

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, 2004 and 2003:

	Year Ended August 31,	
	2004	2003
Audit fees (1)	$1,024,033	$371,175
Audit related fees (2)	$ 1,500	$ 2,100
Tax fees (3)	$	$
All other fees (4)	$	$
Total	$1,025,533	$373,275

(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.

(2) Includes fees related to consultations concerning financial accounting and reporting standards.

(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.

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, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K.

(a) 1. Financial Statements.

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

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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 U.S. Propane L.P, its General Partner.
By U.S. Propane, 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 15, 2004
/s/ Kelcy L. Warren Kelcy L. Warren	Co-Chief Executive Officer and Co-Chairman of the Board (Principal Executive Officer)	November 15, 2004
/s/ H. Michael Krimbill H. Michael Krimbill	President, Chief Financial Officer and Director (Principal Financial and Accounting Officer)	November 15, 2004
/s/ Bill W. Byrne Bill W. Byrne	Director	November 15, 2004
/s/ J. Charles Sawyer	Director	November 15, 2004

J. Charles Sawyer		
/s/ Stephen L. Cropper	Director	November 15, 2004
Stephen L. Cropper		
/s/ David R. Albin	Director	November 15, 2004
David R. Albin		
/s/ Kenneth A. Hersh	Director	November 15, 2004
Kenneth A. Hersh		

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Signature	Title	Date
/s/ Paul E. Glaske Paul E. Glaske	Director	November 15, 2004
/s/ K. Rick Turner K. Rick Turner	Director	November 15, 2004
/s/ Ted Collins, Jr. Ted Collins, Jr.	Director	November 15, 2004
/s/ John W. McReynolds John W. McReynolds	Director	November 15, 2004

INDEX TO FINANCIAL STATEMENTS

Energy Transfer Partners, L.P. and Subsidiaries
(Formerly Energy Transfer Company and surviving legal entity in the Energy Transfer Transactions)

Aquila Gas Pipeline Corporation and Subsidiaries
(The predecessor entity of Energy Transfer Company prior to the formation of Energy Transfer Company in October 2002)

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Oasis Pipe Line Company and Subsidiaries
(An investment of Aquila Gas Pipeline Corporation and
Energy Transfer Company until becoming a wholly owned subsidiary in December 2002)

Heritage Propane Partners, L.P. and Subsidiaries (Heritage)
(The propane operations of Energy Transfer Partners, L.P.
prior to the Energy Transfer Transactions)

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PART I FINANCIAL INFORMATION

The financial statements of Energy Transfer Partners, L.P. presented herein for the year ended August 31, 2004 include the results of operations for Energy Transfer Company for the entire period from September 1, 2003 through August 31, 2004, the results of operations for Heritage Propane Partners, L.P. (referenced herein as Heritage) only 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.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Partners
Energy Transfer Partners, L.P.

We have audited the accompanying consolidated balance sheet of Energy Transfer Partners, L.P. (a Delaware limited partnership) and subsidiaries, formerly Energy Transfer Company as of August 31, 2004 and the related consolidated statements of operations, comprehensive income, partners   capital, and cash flows for the year then ended. 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 audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the 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 audit provides 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, 2004 and the results of their operations and their cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America.

/s/ Grant Thornton LLP

Tulsa, Oklahoma
November 11, 2004

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Partners of
Energy Transfer Company

We have audited the accompanying combined balance sheet of Energy Transfer Company as of August 31, 2003, and the related combined statements of income, partners capital, and cash flows for the eleven-month period 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 audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the 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 audit provides a reasonable basis for our opinion.

In our opinion, the combined financial statements referred to above present fairly, in all material respects, the combined financial position of Energy Transfer Company as of August 31, 2003, and the combined results of their operations and their cash flows for the eleven month period ended August 31, 2003 in conformity with U.S. generally accepted accounting principles.

/s/ ERNST & YOUNG LLP

San Antonio, Texas
December 5, 2003

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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, 2004	August 31, 2003
		(Energy Transfer Company)
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 81,745	$ 53,122
Marketable securities	2,464	
Accounts receivable, net of allowance for doubtful accounts	275,424	105,987
Accounts receivable from related companies	34	
Inventories	54,067	3,947
Deposits paid to vendors	3,023	19,053
Exchanges receivable	8,852	1,373
Price risk management asset	4,615	928
Prepaid expenses and other	6,658	770
Total current assets	436,882	185,180
PROPERTY, PLANT AND EQUIPMENT, net	1,467,649	393,025
INVESTMENT IN AFFILIATES	8,010	6,844
GOODWILL	313,720	13,409
INTANGIBLES AND OTHER ASSETS, net	100,421	3,645
Total assets	$2,326,682	$ 602,103

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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, 2004	August 31, 2003 (Energy Transfer Company)
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES:		
Working capital facility	$ 14,550	$
Accounts payable	274,122	114,198
Accounts payable to related companies	4,276	820
Exchanges payable	2,846	1,410
Customer deposits	11,378	11,600
Accrued and other current liabilities	55,817	8,055
Price risk management liabilities	1,262	823
Income taxes payable	2,252	2,567
Current maturities of long-term debt	30,957	30,000
Total current liabilities	397,460	169,473
LONG-TERM DEBT, less current maturities	1,070,871	196,000
DEFERRED TAXES	109,896	55,385
OTHER NONCURRENT LIABILITIES		157
MINORITY INTERESTS	1,475	
	1,579,702	421,015
COMMITMENTS AND CONTINGENCIES		
PARTNERS CAPITAL:		
Common Unitholders (44,559,031 and 6,621,737 units authorized, issued and outstanding at August 31, 2004 and 2003, respectively)	720,187	180,896
Class C Unitholders (1,000,000 and 0 units authorized, issued and outstanding at August 31, 2004 and 2003, respectively)		
Class D Unitholders (0 authorized, issued and outstanding at August 31, 2004 and 2003)		
Class E Unitholders (4,426,916 and 0 authorized, issued and outstanding at		

August 31, 2004 and August 31, 2003, respectively held by subsidiary and reported as treasury units)		
Special Units (0 authorized, issued and outstanding at August 31, 2004 and 2003)		
General Partner	26,761	192
Accumulated other comprehensive income	32	
Total partners capital	746,980	181,088
Total liabilities and partners capital	$2,326,682	$ 602,103

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, 2004	For the Eleven Months Ended August 31, 2003
	(see Note 2)	(Energy Transfer Company)
REVENUES:		
Midstream and transportation	$ 2,102,101	$ 1,023,468
Propane	342,522	
Other	37,631	
Total revenues	2,482,254	1,023,468
COSTS AND EXPENSES:		
Cost of products sold	2,126,150	901,543
Operating expenses	152,100	27,960
Depreciation and amortization	50,848	13,461
Selling, general and administrative	33,135	15,965
Realized and unrealized (gains) losses on derivatives not accounted for as hedges	(25,499)	2,950
Total costs and expenses	2,336,734	961,879
OPERATING INCOME	145,520	61,589
OTHER INCOME (EXPENSE):		
Interest expense	(41,458)	(12,456)
Equity in earnings of affiliates	363	1,423
Gain (loss) on disposal of assets	(1,006)	
Interest income and other	509	501
INCOME BEFORE MINORITY INTERESTS AND INCOME TAXES	103,928	51,057
Minority interests	(295)	

INCOME BEFORE INCOME TAXES	103,633	51,057
Income tax expense	4,481	4,432
NET INCOME	99,152	46,625
GENERAL PARTNER S INTEREST IN NET INCOME	8,938	932
LIMITED PARTNERS INTEREST IN NET INCOME	$ 90,214	$ 45,693
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 3.45	$ 6.90
BASIC AVERAGE NUMBER OF UNITS OUTSTANDING	26,114,371	6,621,737
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 3.45	$ 6.90
DILUTED AVERAGE NUMBER OF UNITS OUTSTANDING	26,141,605	6,621,737

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

(in thousands)

	For the Year Ended August 31, 2004	For the Eleven Months Ended August 31, 2003
	(see Note 2)	(Energy Transfer Company)
Net income	$ 99,152	$ 46,625
Other comprehensive income:		
Reclassification adjustment for gains on derivative instruments included in net income accounted for as hedges	(3,396)	
Change in value of derivative instruments accounted for as hedges	3,481	
Change in value of available-for-sale securities	(53)	
Comprehensive income	$ 99,184	$ 46,625
Reconciliation of Accumulated Other Comprehensive Income		
Balance, beginning of period	$	$
Current period reclassification to earnings	(3,396)	
Current period change	3,428	
Balance, end of period	$ 32	$

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

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
(FORMERLY ENERGY TRANSFER COMPANY)

CONSOLIDATED STATEMENTS OF PARTNERS CAPITAL

(in thousands, except unit data)

Number of Units										General	Accum Ot Compr
Common	**Class C**	**Class D**	**Class E**	**Special**	**Common**	**Class C**	**Class D**	**Class E**	**Special**	**Partner**	**Inc**
					$	$	$	$	$	$	$
6,621,737					139,180					108	
					(4,815)					(10)	
					46,531					94	
6,621,737					180,896					192	
					(208,927)						
					(52,963)		(5,405)			(5,015)	
16,502,913	1,000,000	7,721,542		3,742,515	103,631		205,382		38,000	(896)	
(4,426,916)			4,426,916		(158,235)			158,235			
			(4,426,916)					(158,235)			
14,375,000					528,129						
					(1,027)		(284)			23,542	
22,240					734						

11,464,057		(7,721,542)		(3,742,515)	256,007		(218,007)		(38,000)		
					42 71,900		18,314			8,938	3
44,559,031	1,000,000				$ 720,187	$	$	$	$	$26,761	$1

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, 2004	Eleven Months Ended August 31, 2003
	(see Note 2)	(Energy Transfer Company)
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 99,152	$ 46,625
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	50,848	13,461
Amortization of deferred finance costs charged to interest	2,642	2,311
Provision for loss on accounts receivable	1,667	
(Gain) loss on disposal of assets	1,006	
Deferred compensation on restricted units and long-term incentive plan	42	
Undistributed earnings of affiliates	(363)	(1,423)
Deferred income taxes	(3,723)	(1,116)
Dividend from subsidiary		1,000
Minority interests	502	
Other noncash, net		(40)
Changes in assets and liabilities, net of effect of acquisitions:		
Accounts receivable	(101,976)	(83,964)
Accounts receivable from related companies	331	
Inventories	34,714	(138)
Deposits paid to vendors	16,030	(19,053)
Exchanges receivable	(7,479)	(1,373)
Prepaid expenses and other	3,192	
Intangibles and other assets	(1,076)	282
Accounts payable	58,278	93,761
Accounts payable to related companies	599	820
Exchanges payable	1,436	1,410
Deposits from customers	(222)	11,600
Accrued and other current liabilites	10,730	4,134
Other long-term liabilities	(157)	157
Income taxes payable	(315)	2,567
Price risk management liabilities, net	(3,163)	(105)
Net cash provided by operating activities	162,695	70,916

CASH FLOWS FROM INVESTING ACTIVITIES:		
Cash paid for acquisitions, net of cash acquired	(681,835)	(306,131)
Capital expenditures	(109,688)	(13,872)
Cash invested in affiliates	(322)	
Proceeds from the sale of assets	1,108	9,843
Net cash used in investing activities	(790,737)	(310,160)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from borrowings	894,079	246,000
Principal payments on debt	(510,084)	(20,000)
Net proceeds from issuance of Common Units	528,129	
Capital contribution from General Partner	22,231	77,706
Distributions to parent	(206,071)	(4,825)
Debt issuance costs	(8,236)	(6,515)
Unit distributions	(63,383)	
Net cash provided by financing activities	656,665	292,366
INCREASE IN CASH AND CASH EQUIVALENTS	28,623	53,122
CASH AND CASH EQUIVALENTS, beginning of period	53,122	
CASH AND CASH EQUIVALENTS, end of period	$ 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, 2004 (see Note 2)	Eleven Months Ended August 31, 2003 (Energy Transfer Company)
NONCASH FINANCING ACTIVITIES:		
Notes payable incurred on noncompete agreements	$ 215	$
Issuance of Common Units in connection with certain acquistions	$ 734	$
General Partner capital contribution	$ 1,311	$
Contributed assets	$ 1,743	$ 31,017
Distributions payable to parent	$ 2,856	
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:		
Cash paid during the period for interest	$ 37,944	$ 8,486
Cash paid during the period for income taxes	$ 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
(FORMERLY ENERGY TRANSFER COMPANY)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollar amounts in thousands, except unit and per unit data)

1. OPERATIONS AND ORGANIZATION:

Energy Transfer Transactions

On January 20, 2004, Heritage Propane Partners, L.P., (Heritage) and La Grange Energy, L.P. (La Grange Energy) completed the series of transactions whereby La Grange Energy 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 of $300,000 less the amount of ETC OLP debt in excess of $151,500, less ETC OLP s accounts payable and other specified liabilities, plus agreed upon capital expenditures paid by La Grange Energy relating to the ETC OLP business prior to closing, $433,909 of Heritage Common and Class D Units, and the repayment of the ETC OLP debt of $151,500. 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 La Grange Energy and an affiliate of La Grange Energy contributed an office building to ETC OLP. La Grange Energy also received 3,742,515 Special Units as consideration for the project it had in progress to construct the Bossier Pipeline. The Special Units converted to Common Units upon the Bossier Pipeline becoming commercially operational on June 21, 2004. The conversion of the Special Units to Common Units was approved by Energy Transfer Partners Unitholders at a special meeting held on June 23, 2004.

Simultaneously with the Energy Transfer Transactions, La Grange Energy obtained control of Heritage by acquiring all of the interest in U.S. Propane, L.P., (U.S. Propane) the General Partner of Heritage, and U.S. Propane, L.P. s general partner, U.S. Propane, L.L.C., from subsidiaries of AGL Resources, Atmos Energy Corporation, TECO Energy, Inc. and Piedmont Natural Gas Company, Inc. for $30,000 (the General Partner Transaction). In conjunction with the General Partner Transaction, U.S. Propane, L.P. contributed its 1.0101% General Partner interest in Heritage Operating, L.P. (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) from U.S. Propane, L.P. for $100,000.

Concurrent with the Energy Transfer Transactions, ETC OLP borrowed $325,000 from financial institutions and Heritage raised $355,948 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 transaction and for general partnership purposes.

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 141, *Business Combinations* (SFAS 141). Although Heritage is the surviving parent entity for legal purposes, ETC OLP is the acquiror 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 within the period, as Heritage s results for the period from September 1, 2003 through January 19, 2004 (the date of the Energy Transfer Transactions) are not included. See Note 2. The operations of Heritage prior to the Energy Transfer Transactions are referred to as Heritage. The assets and liabilities of Heritage were initially recorded at fair value to the extent acquired byLa Grange Energy through its acquisition of the General Partner and limited partner interests of Heritage of approximately 35.4%, determined in accordance with Emerging Issues Task Force (EITF) 90-13 *Accounting for Simultaneous Common Control Mergers* and SFAS 141. 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 have been restated based on the general partner interests and units received by La Grange Energy in the Energy Transfer Transactions. The acquisition of Heritage Holdings by Heritage was accounted for as a capital transaction as the primary asset held by Heritage Holdings is 4,426,916 Common Units of Heritage. Following the acquisition of Heritage Holdings 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.

Costs incurred to construct the Bossier Pipeline are recorded at historical cost. The issuance of the additional Common Units upon the conversion of the Special Units adjusted the percent of Heritage acquired by La Grange Energy in the Energy Transfer Transactions and resulted in an additional fair value step-up being recorded in accordance with EITF 90-13. Upon the conversion of the Special Units on June 23, 2004, La Grange Energy acquired approximately 41.5% of Heritage, and approximately $38,000 additional step-up in the fair value of the assets and liabilities of Heritage was recorded. This does not consider any effects of the TUFCO System transaction or the unit offering that occurred in June 2004.

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)	$ 40,461
Customer lists (15 year life)	15,991
Trademarks	12,152

Goodwill	192,818
	$261,422

The purchase accounting allocations recorded as of August 31, 2004 are preliminary. However, management is in the process of obtaining an independent valuation and does not believe there will be material modifications to the purchase price allocations.

Change of Partnership Name

On February 12, 2004, the Board of Directors of Heritage s General Partner voted to change the name of Heritage 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.

Business Operations

In order to simplify the obligations of Energy Transfer Partners, L.P. (the Partnership) under the laws of several jurisdictions in which it conducts business, the Partnership s activities are conducted through two subsidiary operating partnerships, ETC OLP, a Texas limited partnership which is engaged in midstream and transportation natural gas operations, and 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.

As of August 31, 2004, ETC OLP owned and operated approximately 5,950 miles of natural gas gathering and transportation pipelines with an aggregate throughput capacity of 4.7 billion cubic feet of natural gas per day, with natural gas treating and processing plants located in Texas, Oklahoma, and Louisiana. Its major asset groups consist of the Southeast Texas System, Elk City System, Oasis Pipeline, East Texas Pipeline and TUFCO System. On November 1, 2004, the Partnership closed on the acquisition of certain midstream natural gas assets of Devon

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Energy Corporation (Devon). 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.

HOLP sells propane and propane-related products to more than 650,000 active residential, commercial, industrial, and agricultural customers in 32 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).

2. PRESENTATION OF FINANCIAL INFORMATION:

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 Heritage Holdings beginning January 20, 2004. 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 for the year ended August 31, 2004 include the results of operations of the ET Fuel System beginning June 2, 2004 and the Bossier Pipeline since June 21, 2004.

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. 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 acquiror from the Energy Transfer Transactions. 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 eleven-month period ended August 31, 2003 was treated as a transition period under the rules of the Securities and Exchange Commission and therefore, only an eleven-month period is presented for the period ended August 31, 2003. The accompanying combined financial statements of ETC OLP as of August 31, 2003 present the combined financial statements of ETC OLP and subsidiaries after the elimination of significant intercompany balances and transactions.

The following unaudited pro forma consolidated results of operations are presented as if the ET Fuel System, Oasis Pipe Line Company and ET Company I were wholly owned at the beginning of the periods presented and the Energy Transfer Transactions had been made at the beginning of the periods presented.

	Year Ended August 31, 2004		Eleven Months, Ended August 31, 2003	Year Ended August 31, 2003
	(actual)	(pro forma) (unaudited)	(actual)	(pro forma) (unaudited)

REVENUES:				
Midstream and transportation	$2,102,101	$2,142,935	$ 1,023,468	$1,204,620
Propane Operations	342,522	584,577		510,757
Other	37,631	65,928		60,718
Total revenues	2,482,254	2,793,440	1,023,468	1,776,095
COSTS AND EXPENSES:				
Cost of products sold	2,126,150	2,274,480	901,543	1,310,409
Operating expenses	152,100	220,549	27,960	187,288
Depreciation and amortization	50,848	75,547	13,461	65,278
Selling, general and administrative	33,135	45,251	15,965	36,963
Realized and unrealized (gains) losses on derivatives	(25,499)	(25,499)	2,950	(912)
Total costs and expenses	2,336,734	2,590,328	961,879	1,599,026
OPERATING INCOME	145,520	203,112	61,589	177,069

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	Year Ended August 31, 2004		Eleven Months, Ended August 31, 2003	Year Ended August 31, 2003
	(actual)	(pro forma) (unaudited)	(actual)	(pro forma) (unaudited)
OTHER INCOME (EXPENSE)				
Interest expense	(41,458)	(69,273)	(12,456)	(68,433)
Equity in earnings of affiliates	363	859	1,423	1,120
Gain loss on disposal of assets	(1,006)	(1,006)		
Other	509	305	501	(872)
INCOME BEFORE MINORITY INTERESTS AND INCOME TAXES	103,928	133,997	51,057	108,884
Minority interests	(295)	(636)		(558)
INCOME BEFORE INCOME TAXES	103,633	133,361	51,057	108,326
Income Taxes	4,481	6,058	4,432	15,401
NET INCOME	99,152	127,303	46,625	92,925
GENERAL PARTNER S INTEREST IN NET INCOME	8,938	10,199	932	4,578
LIMITED PARTNERS INTEREST IN NET INCOME	$ 90,214	$ 117,104	$ 45,693	$ 88,347
BASIC EARNINGS PER LIMITED PARTNER UNIT	$ 3.45	$ 3.16	$ 6.90	$ 2.62
BASIC AVERAGE NUMBER OF UNITS OUTSTANDING	26,114,371	37,076,700	6,621,737	33,783,619
DILUTED EARNINGS PER LIMITED PARTNER UNIT	$ 3.45	$ 3.16	$ 6.90	$ 2.61

DILUTED AVERAGE NUMBER OF UNITS OUTSTANDING	26,141,605	37,103,194	6,621,737	33,808,119

	Year Ended August 31, 2004		Eleven Months, Ended August 31, 2003	Year Ended August 31, 2003
	(actual)	(pro forma)	(actual)	(pro forma)
VOLUMES				
Midstream				
Natural gas MMBtu/d	975,000	975,000	524,000	527,000
NGLs bbls/d	12,000	12,000	13,000	14,000
Transportation				
Natural gas MMBtu/d	1,091,000	2,297,000	921,000	2,141,000
Propane operations (in gallons)				
Retail propane	226,209	397,862		375,939
Domestic wholesale	7,071	12,452		15,343
Foreign wholesale	28,648	51,947		58,958

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 unaudited 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:

Principles of Consolidation

La Grange Acquisition is a Texas limited partnership formed on October 1, 2002 and was 99.9% owned by its limited partner, La Grange Energy, L.P., and 0.1% owned by its general partner, LA GP, LLC. La Grange Acquisition is the 99.9% limited partner of ETC Gas Company, Ltd., ETC Texas Pipeline, Ltd., ETC Processing, Ltd., ETC Oklahoma Pipeline, Ltd., ETC Katy Pipeline, Ltd., and ETC Marketing, Ltd. and a

99% limited partner of ETC Oasis, L.P. and ET Company I, Ltd. (collectively, the Operating Companies). The general partners of La Grange Acquisition, La Grange Energy, and the Operating Companies were ultimately owned and controlled by members of La Grange Energy s management, a private equity investor fund, and a group of institutional investors prior to the Energy Transfer Transactions. La Grange Acquisition and the Operating Companies conducted business under the name Energy Transfer Company. The historical financial statements of Energy Transfer Company represent the accounts of La Grange Acquisition and the Operating Companies (collectively ETC OLP) on a combined basis as entities under common control. The accompanying combined financial statements of Energy Transfer Company as of August 31, 2003 and for the eleven months ended August 31, 2003, include the accounts of ETC OLP after the elimination of significant intercompany balances and transactions. Further, ETC OLP s limited partner investments in each of the Operating Companies were eliminated against the Operating Companies limited partner s capital. From October 2002 through December 2002, ETC OLP owned a 20% interest in the Nustar Joint Venture. Effective December 27, 2002, ETC OLP owned a 50% interest in Vantex Gas Pipeline Company, LLC, and a 49.5% interest in Vantex Energy Services, Ltd. These investments are accounted for under the equity method, and are recorded as an investment in affiliates on the Partnership s consolidated balance sheets. All significant intercompany transactions have been eliminated. Prior to December 27, 2002, when the remaining 50% of Oasis Pipe Line Company (Oasis) capital stock was redeemed, ETC OLP accounted for its 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. ETC OLP was contributed by La Grange Energy to Heritage and, thus, after the January 2004 Energy Transfer Transactions, ETC OLP, became wholly owned subsidiaries of the Partnership.

After the Energy Transfer Transactions, the consolidated financial statements of the registrant include the accounts of the Partnership s subsidiaries, including the Operating Partnerships, Heritage Holdings, and MP Energy Partnership, in which HOLP owns a 60% interest. A minority interest liability and minority interest expense is recorded for all partially owned subsidiaries. All significant intercompany transactions and accounts have been eliminated in consolidation.

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 11). Normal allocations according to percentage interests are made, however, only after giving effect to any priority income allocations in an amount equal to the incentive distributions that are allocated 100% to the General Partner.

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. Unrealized holding losses were $53 for the period ended August 31, 2004, and $0 for the eleven months ended August 31, 2003.

Accounts Receivable

The Partnership s midstream and transportation 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 or prepayment). Management reviews midstream and transportation accounts receivable balances each week. Credit limits are assigned and monitored for all counterparties of the midstream and transportation operations. Management believes that the occurrence of bad debt in the Partnership s midstream and transportation segments is not significant; therefore, an allowance for doubtful accounts for the midstream and transportation segments was not deemed necessary at August 31, 2004 and 2003, respectively. Bad debt expense related to these receivables is recognized at the time an account is deemed uncollectible. The bad debt expense recorded during the year ended August 31, 2004 and the eleven months ended August 31, 2003 in the midstream and transportation segments was $123, and $0, respectively.

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.

The Partnership 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 the Partnership s retail and wholesale propane operations and receivables arising from liquids marketing activities. Accounts receivable for retail and wholesale propane and liquids marketing activities are recorded as amounts billed to customers less an allowance for doubtful accounts. The allowance for doubtful accounts for the retail and wholesale propane and liquids marketing 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. Accounts receivable consisted of the following:

	August 31, 2004	August 31, 2003
		(Energy Transfer Company)
Accounts receivable midstream and transportation	$230,101	$ 105,987
Accounts receivable propane	46,990	
Less allowance for doubtful accounts	(1,667)	
Total, net	$275,424	$ 105,987

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

	Year Ended August 31, 2004	Eleven Months Ended August 31, 2003
		(Energy Transfer Company)
Balance, beginning of the period	$	$
Provision for loss on accounts receivable	1,667	
Accounts receivable written off, net of recoveries		

Balance, end of period	$ 1,667	$

Inventories

Midstream and transportation inventories are valued at market prices. These amounts turn over monthly and management believes the costs approximate market value. Propane inventories are 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:

	August 31, 2004	August 31, 2003
		(Energy Transfer Company)
Natural gas, propane and other NGLs	$41,732	$ 1,876
Appliances, parts and fittings and other	12,335	2,071
Total inventories	$54,067	$ 3,947

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Deposits

Deposits are paid to vendors in the midstream and transportation business as prepayments for natural gas deliveries in the following month. The Partnership 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. Deposits with vendors for gas purchases were $3,000 and $16,962 as of August 31, 2004 and 2003, respectively. The Partnership also has deposits with derivative counterparties of $23 and $2,091 as of August 31, 2004 and 2003, respectively.

Deposits are received from midstream and transportation customers as prepayments for natural gas deliveries in the following month and deposits from propane customers as security for future propane use. 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 $11,378 and $11,600 as of August 31, 2004 and 2003, 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.

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:

	August 31,	
	2004	**2003**
		(Energy Transfer Company)
Land and improvements	$ 27,771	$ 992
Buildings and improvements (10 to 30 years)	34,574	992
Pipelines and equipment (10 to 65 years)	833,538	385,448

Natural gas storage (40 years)	24,277	
Bulk storage, equipment and facilities (3 to 30 years)	48,947	
Tanks and other equipment (5 to 30 years)	328,026	
Vehicles (5 to 10 years)	56,922	883
Right of way (20 to 65 years)	59,338	4,057
Furniture and fixtures (3 to 10 years)	7,336	273
Linepack	12,850	5,176
Pad Gas	42,136	
Other (5 to 10 years)	5,581	1,453
	1,481,296	399,274
Less Accumulated depreciation	(57,346)	(13,672)
	1,423,950	385,602
Plus Construction work-in-process	43,699	7,423
Property, plant and equipment, net	$1,467,649	$393,025

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Capitalized interest is included for pipeline construction projects. Interest is capitalized based on the current borrowing rate. As of August 31, 2004, a total of $926 has been capitalized for pipeline construction projects. There was no interest capitalized for the eleven months ended August 31, 2003.

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 No. 143 requires the 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, 2004 because the settlement dates are indeterminable. An asset retirement obligation will be recorded in the periods management can reasonably determine the settlement dates.

Investment in Affiliates

The Partnership owns a 50% interest in Vantex Gas Pipeline Company, LLC, and a 49.5% interest in Vantex Energy Services, Ltd. The Partnership accounts for these investments under the equity method of accounting. 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.

In December 2003, the Partnership purchased a 49% interest in Ranger Pipeline, L.P. (Ranger), which owns a 50% interest in Mountain Creek Joint Venture (Mountain Creek) for $250. 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.

Prior to December 27, 2002, when the remaining 50% of Oasis Pipe Line capital stock was redeemed, the Partnership accounted for its initial 50% ownership in Oasis Pipe Line under the equity method. During the three month period ended December 2002, the Partnership recognized $1.6 million of equity method income from the investment in Oasis Pipe Line. Oasis Pipe Line results from operations are recognized on a consolidated basis effective January 1, 2003.

Effective January 1, 2003, the Partnership sold its interest in the Nustar Joint Venture for approximately $9.6 million. No gain or loss was recognized, as the proceeds equaled the value assigned to the joint venture in the October 2002 purchase allocation.

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Goodwill

Goodwill is associated with acquisitions made for the Partnership s midstream and retail propane segments. There is no goodwill associated with the transportation segment. Of the $313,720 balance in goodwill, $25,442 is expected to be tax deductible. The changes in the carrying amount of goodwill for the years ended August 31, 2004 and the eleven months ended August 31, 2003 were as follows:

	Midstream	Retail Propane	Total
Balance October 1, 2002 (inception)	$	$	$
Goodwill acquired during the year	13,409		13,409
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

The Partnership assesses the impairment of its goodwill in accordance with Statement of Financial Accounting Standards No. 142, *Goodwill and Other Intangible Assets,* (SFAS 142), by determining whether the carrying amount exceeds the fair value of the recognized goodwill asset. If impairment has occurred, the difference between the carrying amount and the fair value is recognized as a loss in the consolidated statements of operations in the period of the impairment. Based on the annual impairment tests performed, there was no impairment as of August 31, 2004 or 2003.

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, 2004		August 31, 2003	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
			(Energy Transfer Company)	
Amortized intangible assets -	$ 27,952	$ (3,006)	$	$

Noncompete agreements (5 to 15 years)				
Customer lists (15 years)	43,756	(2,307)		
Financing costs (3 to 15 years)	18,125	(5,515)	5,724	(2,464)
Consulting agreements (2 to 7 years)	132	(29)		
Other (10 years)	477	(143)	477	(92)
Total	90,442	(11,000)	6,201	(2,556)
Unamortized intangible assets -				
Trademarks	19,719			
Other assets	1,260			
Total intangibles and other assets	$111,421	$(11,000)	$6,201	$(2,556)

Aggregate amortization expense of intangible assets was $8,444 and $2,556 for the year ended August 31, 2004, and the eleven months ended August 31, 2003, respectively. Aggregate amortization expense includes $2,642 and $2,311 from amortization of deferred financing fees that was charged to interest expense for the year ended August 31, 2004 and the eleven-month period ended August 31, 2003, respectively. The estimated aggregate amortization expense for the next five fiscal years is $11,140 for 2005; $10,560 for 2006; $10,170 for 2007; $7,630 for 2008, and $6,075 for 2009.

The Partnership reviews other intangible 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 other intangible assets is not recoverable, the Partnership reduces the carrying amount of such assets to fair value. No impairment of other intangible assets has been recorded as of August 31, 2004 or 2003.

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Accrued and Other Current Liabilities

Accrued and other current liabilities consisted of the following:

	August 31, 2004	August 31, 2003
		(Energy Transfer Company)
Interest payable	$ 6,633	$ 1,014
Wages, payroll taxes and employee benefits	16,012	2,702
Deferred tank rent	4,581	
Taxes other than income	7,185	2,460
Advanced budget payments and unearned revenue	14,632	
Liquids Marketing	1,225	
Other	5,549	1,879
Accrued and other current liabilities	$55,817	$ 8,055

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 for long-term loans with similar terms and average maturities, the aggregate fair value and carrying amount of long-term debt at August 31, 2004 was $1,127,971 and $1,101,828, respectively. At August 31, 2003, the carrying amount of long-term debt approximated its fair value.

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 our midstream revenues and our 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 its systems and is not directly dependent on commodity prices.

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 processes natural gas on behalf of producers, selling the resulting residue gas and NGL volumes at market prices and remitting to producers an agreed upon percentage of the proceeds based on an index price, and (iii) keep-whole arrangements where we gather natural gas from the producer, processes the natural gas and sells the resulting NGLs to third parties at market prices. In many cases, 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 segment results. Under transportation contracts, our customers

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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 on the Oasis Pipeline, (iii) a fuel retention based on a percentage of gas transported on the pipeline, or a combination of the three, generally payable monthly.

Shipping and Handling Costs

In accordance with the Emerging Issues Task Force Issue 00-10, *Accounting for Shipping and Handling Fees and Costs,* the Partnership has classified $35,895 and $10,883 from producer payments for natural gas, compression and treating, which can be considered handling costs, as revenue for the year ended August 31, 2004 and the eleven months ended August 31, 2003, respectively. Costs related to fuel sold are included in cost of sales, while the remaining costs of approximately $19,834 and $8,879 included in operating expenses reflect the cost of fuel consumed for compression and treating for the year ended August 31, 2004 and the eleven months ended August 31, 2003, 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 qualifying cash flow hedges, 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 corporate expenses and compensation for corporate personnel.

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.

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Income Per Limited Partner Unit

Basic net income per limited partner unit is computed by dividing net income, after considering the General Partner s interest, by the weighted average number of Common outstanding. Diluted net income per limited partner unit is computed by dividing net income, after considering the General Partner s interest, by the weighted average number of Common outstanding and the weighted average number of restricted units (Phantom Units) granted under the Restricted Unit Plan. A reconciliation of net income and weighted average units used in computing basic and diluted net income per unit is as follows:

	Year Ended August 31, 2004	Eleven Months Ended August 31, 2003
Basic Net Income per Limited Partner Unit:		
Limited Partners interest in net income	$ 90,214	$ 45,693
Weighted average limited partner units	26,114,371	6,621,737
Basic net income per limited partner unit	$ 3.45	$ 6.90
Diluted Net Income per Limited Partner Unit:		
Limited partners interest in net income	$ 90,214	$ 45,963
Weighted average limited partner units	26,114,371	6,621,737
Dilutive effect of phantom units	27,234	
Weighted average limited partner units, assuming dilutive effect of phantom units	26,141,605	6,621,737
Diluted net income per limited partner unit	$ 3.45	$ 6.90

Unit Based Compensation Plans

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 2.35% for the year ended August 31, 2004, in estimating the present value of the future cash flows of the distributions during the vesting period on the measurement date of each grant. Annual average cash distributions at the grant date were estimated to be $2.22 for the year ended August 31, 2004. The expected life of each grant is assumed to be the minimum vesting period under certain performance criteria of each grant. There were no grants outstanding at August 31, 2003.

Restricted Unit Plan

The General Partner 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 the General Partner and its affiliates. The Restricted Unit Plan provided rights to acquire up to 146,000 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 500 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 the 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. Pursuant to the January 2004 acquisition of the General Partner of the Partnership by La Grange Energy, the change of control provisions of the Restricted Unit Plan were triggered, resulting in the early vesting of 21,600 units by Heritage. Individuals holding 4,500 grants waived their rights to early vesting under the change of control provisions. Heritage recognized compensation expense on the units that vested.

The issuance of the 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 the Common Units. Therefore, no consideration was payable by the plan participants upon vesting and issuance of the 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 8,296 units previously awarded vest), and no additional grants will be made under the Restricted Unit Plan.

Deferred compensation expense recognized under the Restricted Unit Plan for the year ended August 31, 2004 and the eleven months ended August 31, 2003 was $42 and $0, respectively.

Long-Term Incentive Plan

Effective September 1, 2000, the General Partner adopted a long-term incentive compensation plan whereby units were to be awarded to the Executive Officers of the 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 250,000 units and if targeted levels were achieved, a maximum of 500,000 units were available for award under the Long Term Incentive Plan. During the fiscal year ended August 31, 2003, 66,118 units vested pursuant to the vesting rights of the Long-Term Incentive Plan and Common Units were issued. In connection with the acquisition by La Grange Energy of the General Partner in January 2004, 150,018 units vested and Common Units were issued, and the Long-Term Incentive Plan terminated. No deferred compensation expense was recognized under the long-term incentive plan for the year ended August 31, 2004, or the eleven months ended August 31, 2003. Heritage recorded deferred compensation expense of $564 on the units that vested in connection with the acquisition by La Grange Energy of the General Partner in January 2004.

2004 Unit Plan

On June 23, 2004 at a special meeting of the Common Unitholders, the Common Unitholders approved the terms of the Partnership s 2004 Unit Plan (the Plan), which provides for awards of 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 900,000 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. Subsequent to August 31, 2004, awards totaling 129,600 units were made under the 2004 Unit Plan to employees, including executive officers. 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.

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 USP 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

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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 20% 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, 2004, initial Director s Grants totaling 4,000 Units have been 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 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, 2004, there has 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.

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.

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.

Reclassifications

Certain prior period amounts have been reclassified to conform with the 2004 presentation. These reclassifications have no impact on net income or total partners capital.

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. The midstream and transportation segments do not use derivative financial instruments for speculative purposes. At inception, 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 an on-going 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. Generally, management has previously elected not to apply hedge accounting to these contracts, therefore, the net gain or loss arising from marking to market these derivative instruments was previously recognized in earnings as unrealized gains and losses on the statement of operations. However, during the year ended August 31, 2004, the Partnership designated various new futures and certain associated basis contracts as cash flow hedging instruments in accordance with SFAS 133. The effective portion of the hedge gain or loss is initially reported as a component of other comprehensive income and is subsequently reclassified into earnings when the transaction being hedged occurs. The ineffective portion of the gain or loss is reported in earnings immediately. As of August 31, 2004, these hedging instruments had a net fair value of $85, which was recorded as price risk management assets and liabilities on the balance sheet through other comprehensive income. The Partnership reclassified into earnings gains of $3,396 for the year ended August 31, 2004 related to the commodity financial instruments, that were previously reported in accumulated other comprehensive income (loss). The amount of hedge ineffectiveness recognized in income was a gain of $895 for the year ended August 31, 2004. There were no financial instruments designated as hedges for the eleven months ended August 31, 2003.

The Partnership also entered into an interest rate swap agreement for the purpose of mitigating the interest rate risk associated with the ETC OLP Acquisition Term Note. The interest rate swap agreement is used to manage a portion of the exposure to changing interest rates by converting floating rate debt to fixed rate debt. The fair value of the swap was a liability of $539 and $807 as of August 31, 2004 and August 31, 2003, respectively, which is recorded as price risk management liabilities on the balance sheet. The Partnership recorded losses related to the changes in the fair value of the interest rate swap of $1,239 and $312 for the year ended August 31, 2004 and the eleven months ended August 31, 2003, respectively.

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.

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. The values are adjusted to reflect the potential impact of liquidating a position in an orderly manner over a reasonable period of time under present market conditions.

Recently Issued Accounting Standards

In January of 2003, the Financial Accounting Standards Board (FASB) issued Financial Interpretation No. 46 *Consolidation of Variable Interest Entities An Interpretation of ARB No. 51* (FIN 46). In December 2003, the FASB issued FIN 46R, which clarified certain issues identified in FIN 46. FIN 46R requires an entity to consolidate a variable interest entity if the entity is designated as the primary beneficiary of that variable interest entity even if the entity does not have a majority of voting interest. A variable interest entity is generally defined as an entity where its equity is unable to finance its activities or where the owners of the entity lack the risk and rewards of ownership. The provisions of this statement apply at inception of any entity created after January 31, 2003. For an entity created before February 1, 2003, the provisions of this interpretation must be applied at the beginning of the first interim or annual period beginning after March 15, 2004. The implementation of FIN 46 did not have an impact on the Partnership s financial position or results of operations.

As of August 31, 2004, the Partnership owned various unconsolidated entities in which its share of the unconsolidated entities ranges from 49% to 50%. The Partnership accounts for its investments under the equity method of accounting as prescribed by APB Opinion No. 18, *The Equity Method of Accounting for Investments in Common Stock*. The Partnership does not control these entities, and each partner shares in all profits and losses equal to their respective share in the entities. There are no limits on the exposure to losses or on the ability to share in returns. Based on the analysis performed, the Partnership is not the primary beneficiary of the entities, and as a result, will not consolidate the entities but will continue to account for the investment in these entities under the equity method.

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In May 2003, the FASB issued Statement No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity* (SFAS 150). SFAS 150 establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. It requires that an issuer classify a financial instrument that is within the scope of SFAS 150 as a liability (or an asset in some circumstances). This statement is effective for financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. The Partnership adopted the provisions of SFAS 150 as of September 1, 2003. The adoption did not have a material impact on the Partnership s consolidated financial position or results of operations.

4. ACQUISITIONS:

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 is pending completion of an independent appraisal. The results of operations for the ET Fuel System are included in the consolidated income statements beginning on June 2, 2004.

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, which included Edwards Propane of Marshville, North Carolina, Custer Gas Service of Custer, South Dakota, and one other small company. 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. At the closing of the acquisition of Aquila Gas Pipeline s assets, $5,000 was put into escrow until such time that proper consents and conveyance could be achieved related to a sales contract. It was later determined that it was unlikely that a proper conveyance could be achieved which resulted in the escrowed amount of $5,000 being returned to ETC OLP during the eight months ended August 31, 2003. The return of the $5,000 purchase price reduced ETC OLP s basis in property, plant and equipment.

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Assets acquired and purchase price allocation

The assets acquired and purchase price allocation of material acquisitions for the year ended August 31, 2004 and the eleven months ended August 31, 2003 were as follows:

	ET Fuel System June 2, 2004	Aquila Gas Pipeline October 2003
Materials and supplies	$	$ 1,626
Other assets	57	194
Property, plant and equipment	499,789	213,374
Investment in Oasis		41,670
Investment in Nustar Joint Venture		9,600
Deposits from vendor	(750)	
Accrued expenses	(525)	(2,788)
Total	$ 498,571	$ 263,676

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.

5. WORKING CAPITAL FACILITY AND LONG-TERM DEBT:

Long-term debt consists of the following:

	August 31, 2004	August 31, 2003
		(Energy Transfer Company)
1996 8.55% Senior Secured Notes	$ 84,000	$
1997 Medium Term Note Program:		
7.17% Series A Senior Secured Notes	12,000	
7.26% Series B Senior Secured Notes	18,000	
6.50% Series C Senior Secured Notes	1,786	
2000 and 2001 Senior Secured Promissory Notes:		

8.47% Series A Senior Secured Notes	9,600	
8.55% Series B Senior Secured Notes	27,429	
8.59% Series C Senior Secured Notes	27,000	
8.67% Series D Senior Secured Notes	58,000	
8.75% Series E Senior Secured Notes	7,000	
8.87% Series F Senior Secured Notes	40,000	
7.21% Series G Senior Secured Notes	15,200	
7.89% Series H Senior Secured Notes	8,000	
7.99% Series I Senior Secured Notes	16,000	
Term Loan Facility	725,000	226,000
Senior Revolving Acquisition Facility	23,000	

	August 31, 2004	August 31, 2003
		(Energy Transfer Company)
Long term portion of the Senior Revolving Working Capital Facility	10,000	
Notes Payable on noncompete agreements with interest imputed at rates averaging 7.38%, due in installments through 2010	18,218	
Other	1,595	
Current maturities of long-term debt	(30,957)	(30,000)
	$ 1,070,871	$ 196,000

Maturities of the Senior Secured Notes, the Medium Term Note Program and the Senior Secured Promissory Notes (the Notes) are as follows:

1996 8.55% Senior Secured Notes:

mature at the rate of $12,000 on June 30 in each of the years 2002 to and including 2011. Interest is paid semi-annually.

1997 Medium Term Note Program:

Series A Notes:	mature at the rate of $2,400 on November 19 in each of the years 2005 to and including 2009. Interest is paid semi-annually.
Series B Notes:	mature at the rate of $2,000 on November 19 in each of the years 2003 to and including 2012. Interest is paid semi-annually.
Series C Notes:	mature at the rate of $714 on March 13 in each of the years 2000 to and including 2003, $357 on March 13, 2004, $1,073 on March 13, 2005, and $357 in each of the years 2006 and 2007. Interest is paid semi-annually.

2000 and 2001 Senior Secured Promissory Notes:

Series A Notes:	mature at the rate of $3,200 on August 15 in each of the years 2003 to and including 2007. Interest is paid quarterly.
Series B Notes:	mature at the rate of $4,571 on August 15 in each of the years 2004 to and including 2010. Interest is paid quarterly.
Series C Notes:	mature at the rate of $5,750 on August 15 in each of the years 2006 to and including 2007, $4,000 on August 15, 2008 and $5,750 on August 15, 2009 to and including

	2010. Interest is paid quarterly.
Series D Notes:	mature at the rate of $12,450 on August 15 in each of the years 2008 and 2009, $7,700 on August 15, 2010, $12,450 on August 15, 2011 and $12,950 on August 15, 2012. Interest is paid quarterly.
Series E Notes:	mature at the rate of $1,000 on August 15 in each of the years 2009 to and including 2015. Interest is paid quarterly.
Series F Notes:	mature at the rate of $3,636 on August 15 in each of the years 2010 to and including 2020. Interest is paid quarterly.
Series G Notes:	mature at the rate of $3,800 on May 15 in each of the years 2004 to and including 2008. Interest is paid quarterly. $7.5 million of these notes were retired during the fiscal year ended August 31, 2003.
Series H Notes:	mature at the rate of $727 on May 15 in each of the years 2006 to and including 2016. Interest is paid quarterly. $19.5 million of these notes were retired during the fiscal year ended August 31, 2003.
Series I Notes:	mature in one payment of $16,000 on May 15, 2013. Interest is paid quarterly.

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, 2004 the Notes were rated investment grade or better thereby alleviating the requirement that HOLP pay the additional 1% interest.

Effective August 31, 2004, ETC OLP entered into the Third Amendment to the Second Amended and Restated Credit Agreement. The terms of the Agreement are as follows:

A $725,000 Term Loan Facility that matures on January 18, 2008. Amounts borrowed under the ETC OLP Credit Facility bear interest at a rate based on either a Eurodollar rate, or a prime rate. The weighted average interest rate was 4.45% as of August 31, 2004. The Term Loan Facility is secured by substantially all of the ETC OLP s assets. As of August 31, 2004 and 2003, the Term Loan Facility had a balance of $725,000, and $226,000, respectively.

A $225,000 Revolving Credit Facility is available through January 18, 2008. Amounts borrowed under the ETC OLP Credit Facility bear interest at a rate based on either a Eurodollar rate, or a prime rate. The maximum commitment fee payable on the unused portion of the facility is 0.50%. The facility is fully secured by substantially all of ETC OLP s assets. As of August 31, 2004, there were no amounts outstanding under the Revolving Credit Facility, and $4,650 in letters of credit outstanding which reduce the amount available for borrowing under the Revolving Credit Facility. Letters of Credit under the Revolving Credit Facility may not exceed $40,000.

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 3.2038% for the amount outstanding at August 31, 2004. The maximum commitment fee payable on the unused portion of 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, and the capital stock of HOLP s subsidiaries secure the Senior Revolving Working Capital Facility. As of August 31, 2004, the Senior Revolving Working Capital Facility had a balance outstanding of $24,550, of which $10,000 was long-term and $14,550 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. Letter of Credit Exposure plus the Working Capital Loan cannot exceed the $75,000 maximum Working Capital Facility. HOLP had outstanding Letters of Credit of $1,002 at August 31, 2004.

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 3.2038% for the amount outstanding at August 31, 2004. 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, and the capital stock of HOLP s subsidiaries secure the Senior Revolving Acquisition Facility. As of August 31, 2004, the Senior Revolving Acquisition Facility had a balance outstanding of $23,000.

The agreements for each of the Senior Secured Notes, Medium Term Note Program, Senior Secured Promissory Notes, and the Operating Partnerships bank credit facilities contain customary restrictive covenants applicable to the Operating Partnerships, including limitations on substantial disposition of assets, changes in ownership of the Operating Partnerships, the level of additional indebtedness and creation of liens. These covenants require the Operating Partnerships 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 for HOLP and 4.75 to 1.0 during the 365-day period following the funding of the purchase price of the ET Fuel System and to 4.00 to 1.00 during any period other than the 365-day period following the funding of the purchase price of the ET Fuel System for ETC OLP 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 for HOLP and 2.75 to 1 for ETC OLP. 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 Operating Partnerships 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.

Failure to comply with the various restrictive and affirmative covenants of the Operating Partnerships 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 Operating Partnerships are required to measure these financial tests and covenants quarterly and were in compliance with all requirements, tests, limitations, and covenants related to the Senior Secured Notes, Medium Term Note Program and Senior Secured Promissory Notes, and the bank credit facilities as of August 31, 2004.

Future maturities of long-term debt for each of the next five fiscal years and thereafter are $30,957 in 2005; $39,068, in 2006; $72,009 in 2007; $770,756 in 2008; $42,909 in 2009, and $146,129 thereafter.

6. INCOME TAXES:

The components of the federal and state income tax provision (benefit) of the Partnership s taxable subsidiaries is summarized as follows at August 31, 2004 and 2003:

	Year Ended August 31, 2004	Eleven Months Ended August 31, 2003
Current Provision		
Federal	$ 6,505	$ 5,548
State	830	
Total	$ 7,335	$ 5,548
Deferred Provision		
Federal	(2,677)	(1,116)
State	(177)	

Total	$ (2,854)	$ (1,116)
Total tax provision	$ 4,481	$ 4,432
Effective tax rate	4.32%	8.68%

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The effective tax rate is different than the statutory rate due primarily from income attributable to the Partnership earnings not subject to federal and state income taxes. The difference between the statutory rate and the effective rate is summarized as follows:

	Year Ended August 31, 2004	Eleven Months Ended August 31, 2003
Federal income tax rate	35.00%	35.00%
State income tax rate net of federal benefit	3.96%	
Increase (decrease) as a result of:		
Partnership earnings not subject to tax	(31.08%)	(26.32%)
Corporate subsidiary earnings not subject to state tax	(3.56%)	
Effective tax rate	4.32%	8.68%

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, 2004	August 31, 2003
		(Energy Transfer Company)
Property, plant and equipment	$108,661	$ 55,736
Other	1,235	(351)
	$109,896	$ 55,385

7. 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, 2004	Eleven Months Ended August 31, 2003

Midstream Segment:		
BP Energy Company	11.6%	1.5%
Houston Pipeline Company	11.2%	11.1%
Dow Hydrocarbon and Resources, Inc.	10.7%	18.6%

The Partnership s major customers are in the midstream segment. 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 for the year ended August 31, 2004. These concentrations of customers may impact the Partnership s overall exposure to credit risk, either positively or negatively. As of August 31, 2004, the Partnership had a receivable from BP Energy Company that was 13.9% of the Partnership s total net accounts receivable. Management attempts to mitigate its credit risk by establishing strict credit policies for significant accounts receivable.

The Partnership had gross purchases as a percentage of total purchases from major suppliers as follows:

	Year Ended August 31, 2004	Eleven Months Ended August 31, 2003
Midstream Segment:		
Unaffiliated		
BP Energy Company	11.0%	2.1%
Burlington Resources	6.1%	10.1%
Propane Segments (a)		
Unaffiliated		
Enterprise	22.5%	
Dynegy	21.8%	
Affiliated		
M.P. Oils, Ltd.	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 and 28.6%, 13,5% and 19% for the period ended August 31, 2003, respectively.

These concentrations of suppliers may impact the Partnership s overall exposure to credit risk, either positively or negatively. However, managements 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 propane will be readily available in the future, we expect a sufficient supply to continue to be available.

8. 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 $4,283 and $881 for the year ended August 31, 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 $4,794 in 2005; $3,048 in 2006; $2,104 in 2007; $1,647 in 2008; $1,216 in 2009 and $628 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 up to 20 million British thermal units per day (MMBtu/d). Long-term contracts total require delivery of up to 156 MMBtu/d. The long-term contracts run through July 2013.

The Partnership has signed long-term agreements with several parties committing firm transportation volumes into a new pipeline system, which the Partnership was required to construct, and which is referred to as the Bossier Pipeline. 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 Energy Inc. agreement runs nine years beginning when the Bossier

Pipeline becomes operational. The Bossier Pipeline became operational in June 2004.

ETC OLP 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 2005.

Litigation

Although the 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, ETC OLP is not currently a party to any material legal proceedings. 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.

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 with or are named as a defendant in various lawsuits seeking actual and punitive damages for product liability, personal injury and property damage. The Partnership 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 Partnership is a party, none have arisen outside the ordinary course of business except for an action filed by Heritage 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. 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. It is expected that the court will render a final judgment by the end of November 2004. SCANA has publicly stated that it plans to appeal any adverse judgment by the court. The Partnership 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, management cannot yet predict whether the Partnership will receive any of the damages award covered by this verdict. Please read Note 11 for additional discussion of rights relating to the SCANA litigation.

The Partnership 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 the Partnership. 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, the Partnership accrues the related deductible. As of August 31, 2004 and 2003, an accrual of $930 and $112, respectively, was recorded as accrued and other current liabilities on the Partnership s consolidated balance sheets.

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 the Partnership 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.

Petroleum-based contamination or environmental wastes are known to be located on or adjacent to six sites, on which the Partnership 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, Heritage obtained indemnification for expenses associated with any remediation from the former owners or related entities. The Partnership 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, 2004 balance sheet. 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, Heritage 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 Heritage 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 the Partnership, it is believed that the Partnership 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, 2004 and August 31, 2003, an accrual of $473 and $633 was recorded in the Partnership s balance sheets to cover any material environmental liabilities that were not covered by the environmental indemnifications.

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9. 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 until the settlement month. The amount on the balance sheet relating to price risk management assets liabilities in accumulated other comprehensive income will be reclassified into earnings over the next twelve months. When the physical transaction settles, any gain or loss previously recorded in other comprehensive income (loss) on the derivative is recognized in the statement of operations. Unrealized gains or losses on price risk management assets and liabilities that do not meet the requirements for hedge accounting are recognized in the statement of operations. The Partnership s price risk management assets and liabilities were as follows as of August 31, 2004 and 2003:

August 31, 2004:	**Commodity**	**Notional Volume MMBTU**	**Maturity**	**Fair Value**
Basis Swaps IFERC/Nymex	Gas	54,472,500	2004-2005	$ 1,451
Basis Swaps IFERC/Nymex	Gas	62,767,500	2004-2005	592
				$ 2,043
Swing Swaps IFERC	Gas	119,495,000	2004-2005	$ 704
Swing Swaps IFERC	Gas	45,265,000	2004-2005	(399)
Swing Swaps IFERC	Gas	76,720,000	2006-2008	
				$ 305
Futures Nymex	Gas	10,057,500	2004-2005	$(1,311)
Futures Nymex	Gas	12,677,500	2004-2005	2,941
				1,630
		Barrels		
NGL Swaps	Condensate, Propane, Ethane	250,000	2004-2005	$ (86)
August 31, 2003		MMBTU		
Basis Swaps IFERC/Nymex	Gas	24,330,000	2003-2004	$ 612
Basis Swaps IFERC/Nymex	Gas	10,165,000	2003-2004	(184)

				$ 428
Futures Nymex	Gas	3,115,000	2003-2004	$ (56)
Futures Nymex	Gas	5,970,000	2003-2004	540
				$ 484

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 believes it is protected from the volatility in the energy commodities markets because it does not have unbalanced positions. 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.

Interest Rate Risk

The Partnership is exposed to market risk for changes in interest rates related to the bank credit facilities of ETC OLP. An interest rate swap agreement is used to manage a portion of the exposure related to LaGrange Acquisition s Term Loan Facility to changing interest rates by converting floating rate debt to fixed-rate debt. On October 9, 2002, ETC OLP entered into an interest rate swap agreement to manage its exposure to changes in interest rates. The interest rate swap has a notional value of $75,000 and matures on October 9, 2005. Under the terms of the interest rate swap agreement, the Partnership will pay a fixed rate of 2.76% and will receive three-month LIBOR with quarterly settlement commencing on January 9, 2003. The value of the interest rate swap is marked to market and recorded in interest expense. The value of the interest rate swap at August 31, 2004 and August 31, 2003 was a liability of $539 and $807, respectively, and was recorded as a component of price risk management liabilities on the Partnership s consolidated balance sheets.

The following represents gain (loss) on derivative activity:

	Year Ended August 31, 2004	Eleven Months Ended August 31, 2003
		(Energy Transfer Company)
Unrealized gain recognized in earnings related to Partnership s derivative activity	$ 2,919	$ 889
Realized gain (loss) included in revenue	$22,314	$ (2,411)
Unrealized gain on interest rate swap	$ 267	
Realized loss on interest rate swap included in interest expense	$ (1,239)	$ (312)

10. LIQUIDS MARKETING:

HOLP buys and sells derivative financial instruments, which are within the scope of SFAS 133 and that are not designated as accounting hedges. HOLP also enters into energy trading contracts, which are not derivatives, and therefore, are not within the scope of SFAS 133. The types of contracts HOLP utilizes in its liquids marketing segment include energy commodity forward contracts, options, and swaps traded on the over-the-counter financial markets. In accordance with the provisions of SFAS 133, derivative financial instruments utilized in connection with Heritages Operating s liquids marketing activity are accounted for using the mark-to-market method. Under the mark-to-market method of accounting, forwards, swaps, options, and storage contracts are reflected at fair value, and are shown in the consolidated balance sheet as prepaid expenses and other and accrued and other current liabilities. The Partnership applies 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 statement of operations as other revenue. Changes in the assets and liabilities from the liquids marketing activities result primarily from changes in the market prices, newly originated transactions, and the timing and settlement of contracts. Consequently, the Partnership does not apply mark-to-market accounting for any contracts that are not within the scope of SFAS 133. The Partnership attempts to balance its contractual portfolio in terms of notional amounts and timing of performance and delivery obligations. However, net unbalanced positions can exist or are established based on management s assessment of anticipated market movements.

The notional amounts and terms of these financial instruments as of August 31, 2004 include fixed price payor for 345 barrels of propane, and fixed price receiver of 345 barrels of propane. Notional amounts reflect the volume of the transactions, but do not represent the amounts exchanged by the parties to the financial instruments. Accordingly, notional amounts do not accurately measure the Partnership s exposure to market or credit risks.

Estimates related to the Partnership s liquids marketing activities are sensitive to uncertainty and volatility inherent in the energy commodities markets and actual results could differ from these estimates. A theoretical change of 10% in the underlying commodity value of the liquids marketing contracts would not change the market value of the contracts as there were no unbalanced positions at August 31, 2004.

Inherent in the resulting contractual portfolio are certain business risks, including market risk and credit risk. Market risk is the risk that the value of the portfolio will change, either favorably or unfavorably, in response to changing market conditions. Credit risk is the risk of loss from nonperformance by suppliers, customers, or financial counterparties to a contract. The Partnership takes an active role in managing and controlling market and credit risk over liquids marketing activities, and has established control procedures, which are reviewed on an

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ongoing basis. The Partnership monitors market risk of liquids marketing activities through a variety of techniques, including routine reporting to senior management. The Partnership attempts to minimize credit risk exposure through credit policies and periodic monitoring procedures.

The following table summarizes the fair value of liquids marketing contracts, aggregated by method of estimating fair value of the contracts as of August 31, 2004 where settlement had not yet occurred. There were no liquids marketing contracts outstanding at August 31, 2003. Liquids marketing contracts all have a maturity of less than 1 year. The market prices used to value these transactions reflect management s best estimate considering various factors including closing average spot prices for the current and outer months plus a differential to consider time value and storage costs.

Source of Fair Value	**August 31, 2004**
Prices actively quoted	$ 609
Prices based on other valuation methods	902
Assets from liquids marketing	$ 1,511
Prices actively quoted	$ 569
Prices based on other valuation methods	656
Liabilities from liquids marketing	$ 1,225
Unrealized gains	$ 286

The following table summarizes the changes in the unrealized fair value of liquids marketing contracts where settlement had not yet occurred for the year ended August 31, 2004. There were no liquids marketing contracts outstanding at August 31, 2003.

	August 31, 2004
Unrealized gains (losses) in fair value of contracts outstanding at the beginning of the period	$
Unrealized gains (losses) recognized at inception of contracts	
Unrealized gains (losses) recognized as a result of changes in valuation techniques and assumptions	

Other unrealized gains (losses) recognized during the period	1,286
Less: Realized gains (losses) recognized during the period	1,000
Unrealized gains (losses) in fair value of contracts outstanding at the end of the period	$ 286

The gross transaction volumes in barrels for liquids marketing contracts that were physically settled for the years ended August 31, 2004 was 1,042. There were no outstanding liquids marketing contracts for the eleven months ended August 31, 2003.

11. 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, 2004, there were issued and outstanding 44,559,031 Common Units representing an aggregate 98% limited partner interest in the Partnership. There are also 4,426,916 Class E Units outstanding that 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 7).

In connection with the Energy Transfer Transactions in January 2004, the Partnership issued 7,721,542 Class D Units and 3,742,515 Special Units to La Grange Energy, L.P. (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 7,721,542 outstanding Class D Units into 7,721,542 Common Units, (2) the change in terms and conversion of all 3,742,515 outstanding Special Units into 3,742,515 Common Units upon the Bossier 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 U.S. Propane 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 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 20, 2004, the Partnership completed the sale of 8,000,000 Common Units at a public offering price of $38.69. On January 27, the Underwriters for the January 20 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.

On October 21, 2004, the Partnership announced that it received a favorable jury verdict with respect to the SCANA litigation. The jury found in favor of the Partnership on all four claims against SCANA, awarding a total of $48 million in actual and punitive damages. It is expected that the court would render a final judgment by the end of November 2004. SCANA has publicly stated that it plans to appeal any adverse judgment by the court. The Partnership 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, management cannot yet predict whether the Partnership will receive any of the damages award covered by this verdict. 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 La Grange Energy, L.P. 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 4,426,916 Common Units held by Heritage Holdings were converted into 4,426,916 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 $2.82 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 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 $2.82 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 La Grange Energy, L.P. 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. The Class C Units were distributed by Heritage Holdings to its former shareholders. Any amount payable on the Class C Units in the future will reduce the amount otherwise distributable to holders of Incentive Distribution Rights at the time the distribution of such litigation proceeds is made and will not reduce the amount distributable to holders of Common Units. No payments to date have been made on the Class C Units.

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.

On April 14, 2004, the Partnership paid a quarterly distribution of $0.70 per unit, or $2.80 per unit annually, to the Unitholders of record at the close of business on April 2, 2004. On July 15, 2004, the Partnership paid a quarterly distribution of $0.75 per unit, or $3.00 per unit annually, to Unitholders of record at the close of business on July 2, 2004. On September 20, 2004, the Partnership declared a cash distribution for the fourth quarter ended August 31, 2004 of $0.825 per unit, or $3.30 per unit annually, payable on October 15, 2004 to Unitholders of record at the close of business on October 7, 2004. In addition to these quarterly distributions, the General Partner received quarterly distributions for its general partner interest in the Partnership, and incentive distributions to the extent the quarterly distribution exceeded $0.55 per unit. The total amount of distributions paid or declared relating to the quarters in the period from January 20, 2004 through August 31, 2004 on Common Units, the Class D Units, the Class E, the General Partner interests and the Incentive Distribution Rights totaled $89.8 million, $5.4 million,

$9.3 million, $2.3 million and $6.9 million, respectively. All such distributions were made from Available Cash from 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 $0.50 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 $0.55 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 $0.635 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 $0.825 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 $2.82 per year. Please read Note 10 Partners Capital for a discussion of the Class C Units and the percentage interests in distributions of the different classes of units.

12. 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 $1,539 and $0 to the 401(k) savings plan for the year ended August 31, 2004 and the eleven months ended August 31, 2003, respectively.

13. RELATED PARTY TRANSACTIONS:

Accounts payable to related companies as of August 31, 2004 includes $2,856 due to La Grange Energy. This amount represents the balance of funds due to La Grange Energy subject to final settlement of the Energy Transfer Transactions that have not yet been distributed.

Included in midstream and transportation revenues is income from affiliates of $17 and $709 for the year ended August 31, 2004 and the eleven months ended August 31, 2003, respectively. Accounts payable to related companies as of August 31. 2004 includes approximately $1,400 payable to unconsolidated affiliates for purchases of natural gas.

The Partnership s 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 the Partnership in conjunction with the January 2004 Energy Transfer Transactions. The Partnership s Co-Chief Executive Officers, have an indirect ownership 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, in the opinion of management, no less favorable than those available from other providers of compression services. During fiscal year 2004, payments totaling $279 were made to the ETG Entities for compression services provided to and utilized in the Partnership s natural gas midstream operations.

One of the Partnership s natural gas midstream subsidiaries owns 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 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 a director of the General Partner for services the Partnership provided as operator.

Beginning in 2003 and prior to the contribution by an affiliate of La Grange Energy of ET Company I to ETC, ETC had been charged rent by an affiliate for office space in Dallas, which is shared with La Grange Energy and ETC Holdings, L.P., an affiliate of La Grange Energy. For the 11 months ended August 31, 2003 and for the period from October 1, 2003 through January 20, 2004, the rent charged to ETC was $90 and $36, respectively. This office building was contributed to ETC in connection with the Energy Transfer Transaction. Since the Energy Transfer Transaction through August 31, 2004, ETC recognized rental income of $51 for office space occupied by La Grange Energy and its affiliates.

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 ETC Holdings, L.P., had a general and administrative services contract to act as an advisor and provide certain general and administrative services to La Grange Energy and its affiliates, including ETC. The general and administrative services that ET GP, LLC provides La Grange Energy and its subsidiaries under this contract included:

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.

In exchange for these services, La Grange Energy 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, La Grange Energy and its affiliates were also required to reimburse ET GP, LLC for expenses associated with formation of La Grange Energy 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, La Grange Energy charged ETC $449 for expenses associated with its formation. For the eleven months ended August 31, 2003, ETC was charged $375 under this contract. This general and administrative services contract was terminated upon the closing of the Energy Transfer Transaction. As of August 31, 2004, ETC owed La Grange Energy $250 for expenses under the contract from October 1, 2003 through January 20, 2004. This amount was paid subsequent to August 31, 2004.

14. REPORTABLE SEGMENTS:

The Partnership s financial statements reflect six reportable segments: ETC OLP s midstream and transportation operations, HOLP s retail and domestic wholesale propane operations, the foreign wholesale propane operations of MP Energy Partnership, and the liquids marketing activities of Resources. The operations which focus on the

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gathering, compression, treating, processing, transportation and marketing of natural gas, primarily at the Southeast Texas System and Elk City Systems, generate revenue primarily by the volumes of natural gas gathered, compressed, treated, processed, transported, purchased and sold through the Partnership s pipeline (excluding the transportation pipelines) and gathering systems and the level of natural gas and NGL prices. The transportation operations focus on transporting natural gas through the Partnership s Oasis Pipe Line ET Fuel System and Bossier Pipeline. Revenue is generated from fees charged to customers to reserve firm capacity on or move gas on the pipeline on an interruptible basis. The fee structure on the Oasis Pipe Line is derived from the gas price differential between the Waha and Katy hubs. A monetary fee, and/or fuel retention are components of the fee structure. Excess fuel retained after consumption is valued at the first of the month Katy tailgate price and strategically sold when market prices are high.

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 these propane segments separately as each segment involves different distribution, sale, and marketing strategies. Selling, general and administrative expenses are allocated to the midstream and transportation operating segments, however, the Partnership evaluates the performance of its other operating segments based on operating income exclusive of selling, general, and administrative expenses of $11,711 and $0 for the year ended August 31, 2004 and the eleven months ended August 31, 2003, respectively. Investment in affiliates and equity in earnings (losses) of affiliates relates primarily to The Partnership s investment in Vantex Gas Pipeline Company and Vantex Energy Services, Ltd, and is part of the midstream segment. In addition, the Partnership s two largest customers revenues are included in the midstream segment s revenues. The following table presents the unaudited financial information by segment for the following periods:

	Year Ended August 31, 2004	**Eleven Months Ended August 31, 2003**
		(Energy Transfer Company)
Volumes		
Midstream		
Natural gas MMBtu/d	975,000	524,000
NGLs bbls/d	12,000	13,000
Transportation Natural gas MMBtu/d	1,091,000	921,000
Propane gallons (in thousands)		
Retail	226,209	
Domestic wholesale	7,071	
Foreign wholesale		
Affiliated	48,712	
Unaffiliated	28,648	
Elimination	(48,712)	

Total gallons	261,928	

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	Year Ended August 31, 2004	Eleven Months Ended August 31, 2003
		(Energy Transfer Company)
Revenues:		
Midstream		
Unaffiliated	$2,015,944	$ 990,818
Affiliated	17	709
Eliminations	(27,798)	(9,559)
Transportation	113,938	41,500
Retail propane	315,177	
Domestic wholesale propane	5,358	
Foreign wholesale propane		
Affiliated	21,868	
Unaffiliated	21,987	
Eliminations	(21,868)	
Liquids marketing, net	863	
Other propane related	36,768	
Total	$2,482,254	$1,023,468
Cost of sales:		
Midstream	$1,932,575	$ 908,979
Eliminations	(27,798)	(9,559)
Transportation	11,270	2,123
Retail propane	174,769	
Domestic wholesale propane	4,742	
Foreign wholesale propane	20,129	
Other	10,463	
Total Cost of Sales	$2,126,150	$ 901,543
Operating Income		
Midstream	$ 66,680	$ 43,900
Transportation	56,299	17,689
Retail propane and other	33,726	
Domestic wholesale propane	(1,737)	
Foreign wholesale propane		
Affiliated	408	

Unaffiliated	1,843	
Elimination	(408)	
Liquids marketing	420	
Selling general and administrative expenses not allocated to segments	(11,711)	
Total	$ 145,520	$ 61,589
Gain (loss) on Disposal of Assets:		
Midstream	$ (6)	$
Transportation	(1)	
Retail propane	(999)	
Corporate	0	
Domestic wholesale propane	0	
Total	$ (1,006)	$
Minority Interest Expense:		
Corporate	$	$
Foreign wholesale propane	295	
Total	$ 295	$

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	Year Ended August 31, 2004	Eleven Months Ended August 31, 2003
		(Energy Transfer Company)
Depreciation and amortization:		
Midstream	$11,886	$ 10,647
Transportation	7,426	2,814
Retail propane	31,104	
Domestic wholesale propane	417	
Foreign wholesale propane	15	
Total	$50,848	$ 13,461
Interest Expense		
Midstream	$17,632	$ 11,924
Transportation	6,685	5,097
Eliminations	(5,999)	(4,565)
Retail propane	23,140	
Total	$41,458	$ 12,456
Earnings from equity investments		
Midstream	$ 499	$ (149)
Transportation		1,572
Foreign wholesale	(136)	
Total	$ 363	$ 1,423
Income tax expense		
Transportation	$ 1,716	$ 4,432
Corporate	2,765	
Total	$ 4,481	$ 4,432

	August 31, 2004	August 31, 2003 (Energy Transfer Company)
Total Assets:		
Midstream	$ 615,339	$ 413,096
Transportation	785,754	189,007
Retail propane	870,200	
Domestic wholesale propane	12,567	
Foreign wholesale propane	10,034	
Liquids marketing	8,952	
Corporate	23,836	
Total	$ 2,326,682	$ 602,103

	Year Ended August 31, 2004	Eleven Months Ended August 31, 2003 (Energy Transfer Company)
Additions to property, plant and equipment including acquisitions:		
Midstream	$ 26,339	$ 277,767
Transportation	570,169	42,236
Retail propane	515,284	
Domestic wholesale propane	4,492	
Foreign wholesale propane	528	
Corporate	3,229	
Total	$ 1,120,041	$ 320,003

Corporate assets include vehicles, office equipment and computer software for the use of administrative personnel. These assets are not allocated to segments.

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15. 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.

	Quarter Ended			
Fiscal 2004:	**(Energy Transfer Company) November 30**	**February 29**	**May 31**	**August 31**
Revenues	$414,986	$629,287	$642,175	$795,806
Gross Profit	34,382	97,435	112,045	112,242
Operating income	21,004	58,619	36,187	29,710
Net income	15,694	49,239	21,330	12,889
Basic and diluted net income per limited partner unit	$ 2.32	$ 2.38	$ 0.52	$ 0.22

	Quarter Ended			
	(Energy Transfer Company)			
Fiscal 2003	**Period from inception (October 1, 2002) through November 30**	**February 28**	**May 31**	**August 31**
Revenues	$78,319	$204,040	$372,586	$368,523
Gross Profit	10,998	29,536	42,936	38,455
Operating income	3,733	12,226	24,848	20,782
Net income	3,728	7,839	18,827	16,231
Basic and diluted net income per limited partner unit	$ 0.55	$ 1.16	$ 2.79	$ 2.40

Certain amounts from previously reported quarters have been reclassified to conform with current presentation. These reclassifications have no impact on net income or total partners capital.

16. SUBSEQUENT EVENTS:

On November 1, 2004 the Partnership announced the closing of the acquisition of certain midstream natural gas assets of Devon Energy Corporation (Devon) for approximately $64.6 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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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Partners of
La Grange Acquisition, LP and Affiliates

We have audited the accompanying consolidated balance sheets of Aquila Gas Pipeline Corporation and Subsidiaries as of September 30, 2002, and the related consolidated statements of income, stockholder s equity and cash flows for the period ended September 30, 2002 and the year ended December 31, 2001. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audit.

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 financial statements referred to above present fairly, in all material respects, the consolidated financial position of Aquila Gas Pipeline Corporation and Subsidiaries as of September 30, 2002, and the results of their operations and their cash flows for the period ended September 30, 2002 and the year ended December 31, 2001 in conformity with accounting principles generally accepted in the United States.

As discussed in the Note 1 to the consolidated financial statements, effective January 1, 2002, Aquila Gas Pipeline Corporation and Subsidiaries adopted Statement of Financial Accounting Standards No. 142, Goodwill and Other Intangible Assets.

/s/ ERNST & YOUNG LLP

San Antonio, Texas
July 17, 2003

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AQUILA GAS PIPELINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEET
(in thousands)

	September 30, 2002
ASSETS	
Current assets:	
Cash and cash equivalents	$
Accounts receivable	72,154
Inventories and exchanges, net	
Materials and supplies	2,622
Price risk management assets	18,100
Other current assets	66
Receivable due from affiliated companies	23,889
Total current assets	116,831
Pipeline, property, plant and equipment, at cost:	
Natural gas pipelines	465,441
Plants and processing equipment	93,872
Other	12,425
	571,738
Less accumulated depreciation	(210,399)
	361,339
Intangible assets, net	5,218
Investment in Oasis Pipe Line	100,748
Other, net	475
Price risk management assets	16,917
Total assets	$ 601,528
LIABILITIES AND STOCKHOLDER S EQUITY	
Current liabilities:	
Accounts payable	$ 71,981
Accrued expenses	3,938
Current maturities of long-term debt	
Accrued interest	975
Exchanges payable	784

Price risk management liabilities	19,334
Payable to affiliated companies	47,064
Total current liabilities	144,076
Long-term debt	66,250
Deferred income taxes	121,718
Price risk management liabilities	15,225
Commitments and contingencies	
Stockholder s equity:	
Common stock, $1.00 par value, 1,000 shares authorized and 10 shares issued	
Additional paid-in capital	90,591
Retained earnings	163,668
Total stockholder s equity	254,259
Total liabilities and stockholder s equity	$ 601,528

See accompanying notes.

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AQUILA GAS PIPELINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

	Nine Months Ended September 30, 2002	Year Ended December 31, 2001
	(In thousands)	
Operating revenues	$933,099	$ 1,813,850
Costs and expenses:		
Cost of sales	880,064	1,715,261
Operating	12,717	18,126
General and administrative	9,575	19,949
Depreciation and amortization	22,915	30,779
Asset impairment		
Unrealized loss (gain) on derivatives	4,966	(13,255)
Total costs and expenses	930,237	1,770,860
Income from operations	2,862	42,990
Other income (expense)	(84)	1,901
Equity in net income of Oasis Pipe Line	5,425	3,128
Interest and debt expenses, net	(3,931)	(6,858)
Income before income taxes	4,272	41,161
Income tax (benefit) expense	(467)	15,403
Net income	$ 4,739	$ 25,758

See accompanying notes.

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AQUILA GAS PIPELINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDER S EQUITY
Nine months ended September 30, 2002, and

Year ended December 31, 2001

	Common Stock Shares	Amount	Additional Paid-in Capital	Retained Earnings	Total Stockholder s Equity
				(In thousands)	
Balance, December 31, 2000		$	$90,591	$133,171	$223,762
Net income	—			25,758	25,758
Balance, December 31, 2001			90,591	158,929	249,520
Net income	—			4,739	4,739
Balance, September 30, 2002		$	$90,591	$163,668	$254,259

See accompanying notes.

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AQUILA GAS PIPELINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine Months Ended September 30, 2002	Year Ended December 31, 2001
	(In thousands)	
Operating Activities		
Net income	$ 4,739	$ 25,758
Adjustments to reconcile net (loss) income to net cash provided by operating activities:		
Depreciation and amortization, including interest	22,935	30,827
Equity in (income) loss of Oasis Pipe Line	(5,425)	(3,128)
Dividend from Oasis	4,000	1,500
Deferred income taxes	(956)	9,843
Gain or loss on sale of assets	61	(3,838)
Asset impairment		
Changes in operating assets and liabilities:		
Accounts receivable	48,939	102,688
Inventories and exchanges, net	1,973	925
Net change in price risk management assets and liabilities	7,168	(7,056)
Receivable due from affiliated companies	(13,499)	(10,390)
Other assets	455	(171)
Accounts payable	(59,137)	(98,802)
Accrued expenses	(4,531)	(1,739)
Accrued interest	706	(812)
Payable to affiliated companies	5,559	19,593
Net cash provided by operating activities	12,987	65,198
Investing Activities		
Additions to pipeline, property, plant and equipment	(5,486)	(26,866)
Proceeds from asset dispositions	4,999	6,139
Net cash used in investing activities	(487)	(20,727)
Financing Activities		
(Payments) borrowings under revolving credit agreement, net		(31,971)
Principal payments of debt	(12,500)	(12,500)
Net cash used in investing activities	(12,500)	(44,471)

Net (decrease) increase in cash and cash equivalents				
Cash and cash equivalents, beginning of year				
Cash and cash equivalents, end of year	$		$	

See accompanying notes.

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AQUILA GAS PIPELINE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
Nine Months Ended September 30, 2002, and

Year Ended December 31, 2001

(In thousands)

1. Summary of Business, Basis of Presentation and Significant Accounting Policies

Business

Aquila Gas Pipeline Corporation (Aquila Gas Pipeline or the Company) and subsidiaries owned and operated natural gas gathering and pipeline systems and gas processing plants and was engaged in the business of purchasing, gathering, transporting, processing and marketing natural gas and natural gas liquids (NGLs) in the States of Texas and Oklahoma.

Effective October 1, 2002, substantially all of the operating assets of Aquila Gas Pipeline were sold for $264 million to La Grange Acquisition, LP (La Grange Acquisition). La Grange Acquisition did not assume Pipeline s derivative positions or its liabilities, except for certain payables.

Principles of Consolidation and Basis of Presentation

Aquila Gas Pipeline was a wholly owned subsidiary of Aquila Merchant Services. Aquila Merchant Services was wholly owned by Aquila, Inc. (Aquila), formerly UtiliCorp United Inc.

The accompanying consolidated financial statements include the accounts of Aquila Gas Pipeline after the elimination of significant intercompany balances and transactions with subsidiaries. Unless otherwise indicated, all amounts included in the notes to the consolidated financial statements are expressed in thousands.

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure 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 more significant areas requiring the use of estimates relate to the fair value of financial instruments and useful lives for depreciation. Actual results may differ from those estimates.

The Company was subject to a number of risks inherent in the industry in which it operated, primarily fluctuating prices and gas supply. The Company s financial condition and results of operations depended significantly upon the prices received for natural gas and NGLs. These prices were subject to wide fluctuations due to a variety of factors that were beyond the control of the Company. In addition, the Company had to continually connect new wells to its gathering systems in order to maintain or increase throughput levels to offset natural declines in dedicated volumes. The number of new wells drilled depended on a variety of factors that were beyond the control of the Company.

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AQUILA GAS PIPELINE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Cash Paid for Interest

The following provides information related to cash paid for interest. No cash was paid for income taxes as taxes were settled through intercompany accounts with Aquila:

	September 30, 2002	December31 2001
	(In thousands)	
Interest, net of amount capitalized	$3,308	$6,219

Revenue Recognition

Operating revenues were recognized upon the delivery of natural gas or NGLs to the buyer of the related product or services.

Inventories and Exchanges

Inventories and exchanges consisted of NGLs on hand or natural gas and NGLs delivery imbalances with others and were presented net by customer/supplier on the consolidated balance sheet. These amounts turned over monthly, and management believed that cost approximated market value. Accordingly, these volumes were valued at market prices on the consolidated balance sheet.

Materials and Supplies

Materials and supplies were stated at the lower of cost (determined on a first-in, first-out basis) or market.

Shipping and Handling Costs

In accordance with the Emerging Issues Task Force Issue 00-10, Accounting for Shipping and Handling Fees and Costs , the Company classified all deductions from producer payments for fuel, compression and treating that can be considered handling costs as revenue. The associated fuel costs were included in cost of sales, while the remaining costs were included in operating costs.

Commodity Risk Management

In 1999, Aquila Gas Pipeline transferred all of its energy trading operations and management thereof to Aquila Energy Marketing (AEM), a wholly owned subsidiary of Aquila. AEM entered into forward physical contracts with third parties for the benefit of Aquila Gas Pipeline and where deemed necessary entered into intercompany financial derivative positions (e.g., swaps, futures and options) with Aquila Gas Pipeline and other affiliates to assist them in managing their exposures. Thus, Aquila Gas Pipeline had forward physical contracts with third parties and financial

AQUILA GAS PIPELINE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

derivative positions with AEM and affiliates. The Company received all gross margins associated with these transactions, and AEM charged Aquila Gas Pipeline for its share of AEM s costs to manage Aquila Gas Pipeline s positions.

The Company accounted for its derivative positions, both speculative forward positions and financial derivatives, under Emerging Issues Task Force Issue 98-10, Accounting for Contracts Involved in Energy Trading and Risk Management Activities (EITF 98-10). Under EITF 98-10, the Company valued the derivative positions at market value with all changes being recognized in earnings. Realized gains and losses were included in revenues, while unrealized gains and losses were classified as such on the consolidated statements of income. Aquila Gas Pipeline s derivative positions were classified as current or long-term price risk management assets and liabilities based on their maturity.

The market prices used to value these transactions reflected management s estimates considering various factors, including closing exchange and over-the-counter quotations, time value and volatility factors of the underlying commitments. The values were adjusted to reflect the potential impact of liquidating a position in an orderly manner over a reasonable period of time under market conditions.

Although La Grange Acquisition is also involved in energy marketing and uses derivatives to manage its exposures, La Grange Acquisition did not purchase Aquila Gas Pipeline s derivative positions when it purchased its assets. Emerging Issues Task Force Issue 02-03, Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities was issued in the fourth quarter of 2002 and rescinded the provisions of EITF 98-10. As such all energy trading derivative transactions are now governed by Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities (Statement No. 133). Under Statement No. 133, La Grange Acquisition will continue to account for its financial derivative positions as mark to market instruments. However, as permitted under Statement No. 133, La Grange Acquisition has adopted a policy of treating all forward physical contracts that require physical delivery as normal purchases and sales contracts. As such, these contracts will not be marked to market and will be accounted for when delivery occurs. Had Aquila Gas Pipeline adopted this policy, it would have reversed unrealized mark to market gains of $1,938 at September 30, 2002.

Pipeline, Property, Plant and Equipment

Pipeline, property, plant and equipment were stated at cost. Additions and improvements that added to the productive capacity or extended the useful life of the asset were capitalized. Expenditures for maintenance and repairs that did not add capacity or extended the useful life were charged to expense as incurred. Upon disposition or retirement of pipeline components or gas plant components, any gain or loss was recorded to accumulated depreciation. When entire pipeline systems, gas plants or other property and equipment were retired or sold, any gain or loss was included in operations.

Depreciation of the pipeline systems, gas plants and processing equipment was calculated using the straight-line method based on an estimated useful life of primarily 25 years. Interest cost on funds used to finance major pipeline projects during their construction period was also capitalized. Capitalized interest cost was $35 and $86 for the periods ending September 30, 2002 and December 31, 2001, respectively.

The Company reviewed its long-lived assets, including finite lived intangibles, for impairment whenever facts and circumstances indicated impairment was potentially present. When impairment indicators were present, Aquila Gas Pipeline evaluated whether the assets in question were able to generate sufficient cash flows to recover their carrying value on an undiscounted basis. If not, the Company impaired the assets to their fair value, which was determined based on discounted cash flows or estimated salvage value.

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AQUILA GAS PIPELINE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Construction work in progress at September 30, 2002 was $669.

Stock Compensation

Some of Aquila Gas Pipeline s employees received stock options in Aquila. As permitted under generally accepted accounting principles, Aquila elected to account for the options under Accounting Principles Board Opinion No. 25, and because the options strike price was equal to or greater than the fair value at the date of grant, no compensation expense was recognized. See Note 6, for a summary of the options granted. As these were Aquila options, Aquila Gas Pipeline does not have full access to the information necessary to disclose what compensation expense would have been, had Aquila accounted for the options under Statement of Financial Accounting Standards No. 123, Accounting for Stock-Based Compensation , which requires compensation expense be recognized for the fair value of the options at the date of grant. La Grange Acquisition does not have a stock option plan in place for its employees.

Income Taxes

Aquila Gas Pipeline was included in the consolidated federal income tax returns filed by Aquila. Accordingly, all tax balances were ultimately settled through Aquila. Aquila Gas Pipeline had generally accounted for its taxes on a stand-alone or separate return basis (see Note 4). Periodically, taxes payable were settled through the intercompany accounts with Aquila and were not funded in cash.

The Company provides for income taxes in accordance with Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes (Statement No. 109). Statement No. 109 requires that deferred tax assets and liabilities be established for the basis differences between the reported amounts of assets and liabilities for financial reporting purposes and income tax purposes.

Equity Method Investments

Aquila Gas Pipeline had a 50% investment in Oasis Pipe Line Company. Aquila Gas Pipeline accounted for this investment using the equity method.

Adoption of New Accounting Standard

On January 1, 2002, Aquila Gas Pipeline adopted Statement of Financial Accounting Standards No. 141, Business Combinations (Statement No. 141). Statement No. 141 addresses financial accounting and reporting for business combinations and supersedes APB Opinion No. 16, Business Combinations , and FASB Statement 38, Accounting for Preacquisition Contingencies of Purchased Enterprises. Statement No. 141 was effective for all business combinations initiated after June 30, 2001. Statement No. 141 eliminated the pooling-of-interest method of accounting for business combinations. Statement No. 141 also changed the criteria to recognize intangible assets apart from goodwill. As the Company has historically used the purchase method to account for all business combinations, adoption of this statement did not have a material impact on the Aquila Gas Pipeline s financial position or results of operations.

In June 2001, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards

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AQUILA GAS PIPELINE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

No. 142, Goodwill and Other Intangible Assets (Statement No. 142). Statement No. 142 addresses financial accounting and reporting for acquired goodwill and other intangible assets and superseded APB Opinion No. 17, Intangible Assets. Statement No. 142 was effective for fiscal years beginning after December 15, 2001. This statement established new accounting for goodwill and other intangible assets recorded in business combinations. Under the new rules, goodwill and intangible assets deemed to have indefinite lives are no longer amortized but are be subjected to annual impairment tests in accordance with the statement. Other intangible assets continue to be amortized over their useful lives. Aquila Gas Pipeline adopted this standard on January 1, 2002. As amortization of goodwill was a significant non-cash expense, Statement No. 142 had a material impact on the Company s financial statements. The table below summarizes the financial results as if adoption had occurred on January 1, 2001.

	2001
	(In thousands)
Reported net income	$25,758
Add back: Goodwill amortization	900
Add back: Oasis excess basis amortization	1,650
Taxes	(365)
Adjusted net income	$27,943

2. Related-Party Transactions

Aquila Gas Pipeline entered into various types of transactions with Aquila and its affiliates. Aquila Gas Pipeline sold natural gas to Aquila and its affiliates and purchased natural gas and NGLs from Aquila. Additionally, Pipeline reimbursed Aquila for the direct and indirect costs of certain Aquila employees who provided services to the Company and for other costs (primarily general and administrative expenses) related to the Company s operations. Aquila also provided Aquila Gas Pipeline with a revolving credit agreement, as described in Note 3.

The following table summarizes transactions for the indicated periods:

	September 30, 2002	December 31, 2001
	(In thousands)	
Natural gas sales to affiliated companies	$166,372	$325,295
NGLs sales to affiliated companies	373	1,267
Purchases of natural gas from affiliated companies	101,398	170,105
Purchases of NGLs from affiliated companies	1,841	

Transportation expense with Oasis	3,900	6,727
Recognized (loss) gain from marketing transactions with AEM	2,678	(10,605)
Interest expense with Aquila	3,295	5,140
Reimbursement of direct costs to Aquila	(1,739)	15,283
Service agreement expenses charged by Aquila	2,628	3,504

The affiliated receivable due from Aquila was $23,889 for the period ending September 30, 2002. This receivable was created by overpayments on Aquila Gas Pipeline s revolving credit agreement (see Note 3) with Aquila. The affiliated payable due to Aquila was $47,064 as of September 30, 2002.

AQUILA GAS PIPELINE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

3. Debt

The following table summarizes Aquila Gas Pipeline s long-term debt:

	September 30, 2002
	(In thousands)
Loan agreement bearing interest at 6.83%, due 2006	$ 16,250
Loan agreement bearing interest at 6.47%, due 2005	50,000
8.29% senior notes, due 2002	
Total debt	66,250
Less Current maturities of long-term debt	
Total long-term debt	$ 66,250

Revolving Credit Agreement

Aquila Gas Pipeline had a credit agreement, as amended, with Aquila that provided a revolving credit facility (Revolver) for borrowings of up to $115,000. As of September 30, 2002, there was $115,000 available for use under the Revolver. Aquila swept all available cash daily to reduce the revolver. This resulted in a receivable due to Aquila Gas Pipeline of $23,889 as of September 30, 2002. The Revolver bore interest at Aquila Gas Pipeline s election of either (i) a base rate (the higher of the bank prime rate or 1/2 of 1 percent above the Federal Funds rate), (ii) an adjusted certificate of deposit rate or (iii) a Eurodollar rate. The maturity date of the Revolver automatically renewed in one-year periods from each commitment period (October of any given year), unless Aquila gave at least a one-year notice not to renew. As of September 30, 2002, the maturity date was October 2003. The Revolver was unsecured and was subordinate to the 8.29% senior notes described below. The Company paid an annual commitment fee to Aquila of 1/4 of 1% on the unutilized portion of the revolving credit facility. The Revolver required the Company to comply with certain restrictive covenants. At September 30, 2002, Aquila Gas Pipeline was in compliance with such covenants.

Loan Agreements

In 1995, Aquila Gas Pipeline entered into a loan agreement with Aquila Energy, a subsidiary of Aquila for $50,000. The loan was unsecured and bore interest at 6.47% due semi-annually. The principal amount of the loan was to be repaid to Aquila Energy by June 1, 2005. In 1997, Aquila Gas Pipeline entered into a second loan agreement with Aquila Energy for $16,250. This loan was unsecured and bore interest at 6.83% due semi-annually. The principal amount of the second loan was to be repaid to Aquila Energy by October 15, 2006.

Senior Notes

The 8.29% Senior Notes (Senior Notes) were unsecured and interest payments were due semi-annually. Principal payments of $12,500 were required each year and the balance was paid in full in September 2002. Upon issuance of the Senior Notes, Aquila Gas Pipeline deferred approximately $1,886 of initial fees and expenses that were amortized over the life of the notes.

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AQUILA GAS PIPELINE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. Income Taxes

Components of income tax provision/(benefit) attributable to income before taxes are as follows:

	September 30, 2002	December 31, 2001
	(In thousands)	
Current	$ 489	$ 5,560
Deferred	(956)	9,843
Total	$ (467)	$ 15,403

Tax expense was different than the amount computed by applying the statutory federal income tax rate to income before taxes. A reconciliation of Aquila Gas Pipeline s income taxes with the United States Federal statutory rate is as follows:

	September 30, 2002	December 31, 2001
	(In thousands)	
Book income at U.S. federal statutory rate	35.0%	35.0%
Equity method earnings	(51.4)	(3.3)
State taxes	3.5	3.5
Other	2.0	2.0
Tax provision effective rate	(10.9)%	(37.2)%

Deferred taxes resulted from the effect of transactions that were recognized in different periods for financial and tax reporting purposes. Significant components of the Company s deferred tax assets and liabilities were as follows:

	September 30, 2002

	(In thousands)
Deferred tax assets:	
Basis difference in intangible assets	$ 6,649
Other	388
Total deferred tax assets	7,037
Deferred tax liabilities:	
Basis difference in fixed assets	(128,755)
Net deferred tax liabilities	$(121,718)

5. Major Customers

The Company s gross sales as a percentage of total revenues to nonaffiliated major customers were as follows:

	September 30, 2002	December 31, 2001
Customer A	17.5%	15.4%
Customer B	9.6%	11.0%

AQUILA GAS PIPELINE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The Company s natural gas operations had a concentration of customers in natural gas transmission, distribution and marketing as well as industrial end-users, while its NGLs operations had a concentration of customers in the refining and petrochemical industries.

These concentrations of customers impacted the Company s overall exposure to credit risk, whether positively or negatively, in that the customers were similarly affected by changes in economic or other conditions. However, management believed that Aquila Gas Pipeline s portfolio of accounts receivable was sufficiently diversified to minimize any potential credit risk. Historically, Aquila Gas Pipeline has not incurred significant problems in collecting its accounts receivable and, as such, no allowance for doubtful accounts was provided in the accompanying consolidated financial statements. The Company s accounts receivable were generally not collateralized.

6. Retirement and Benefit Plans

Aquila had a defined contribution plan for virtually all employees. Pursuant to the plan, employees of the Company could defer a portion of their compensation and contribute it to a deferred account. The Company s matching contributions to the plan were $408 and $444 for the periods ended September 30, 2002 and December 31, 2001, respectively.

Aquila had a stock contribution plan under which eligible Aquila Gas Pipeline employees received a company contribution of 3 percent of their base income in Aquila common stock. The Company s expense associated with this plan was $27 and $231 for periods ending September 30, 2002 and December 31, 2001, respectively. The reduction for 2002 was due to the reduction in the number of employees eligible in 2002 and declines in the market value of the stock.

Aquila had a stock option plan under which eligible Aquila Gas Pipeline employees were granted options to purchase shares of Aquila s common stock. The plan provided that the options would not be granted at a price below the market price at the date of grant. Accordingly, no compensation cost was recognized for the options. The options vested one year from the date of grant and expired 10 years from the date of grant.

The following table summarizes the options granted to Aquila Gas Pipeline employees:

	September 30, 2002		Period Ended December 31, 2001	
	Options	**Average Price**	**Options**	**Average Price**
	(In thousands)			
Outstanding, beginning of period	170,298	$26.8387	115,876	$21.9475
Granted			85,810	34.8028
Exercised	(825)	18.2083	(25,688)	23.4483
Forfeited	(4,637)	22.7246	(5,700)	21.6565

Outstanding, end of period	164,836	$26.6896	170,298	$26.8387

AQUILA GAS PIPELINE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

7. Commitments and Contingencies

Lease Obligations

The Company had various non-cancelable operating leases. Total lease expense amounted to approximately $598 for the period ending September 30, 2002, and $1,059 for the period ending December 31, 2001. All leases were transferred to La Grange Acquisition effective October 1, 2002.

The following summarizes the future annual lease payments for the transferred leases for each of the next five years as of September 30, 2002:

	(In thousands)
2003	$775
2004	775
2005	773
2006	64
2007 and thereafter	

Taxes

The IRS has examined and proposed adjustments to Aquila s consolidated federal income tax returns for 1988 through 1993. The proposed adjustment affecting the Company was to lengthen the depreciable life of certain pipeline assets owned by Aquila Gas Pipeline. Aquila has filed a petition in U.S. Tax Court contesting the IRS proposed adjustments for the years 1990 through 1991. The IRS has also proposed an adjustment on the same issue for 1992 through 1998. Aquila has tentatively agreed with the IRS to hold this issue in abeyance pending the outcome of the earlier petition.

Aquila intends to vigorously contest the proposed adjustment and believes it is reasonably possible that they will prevail. If resolved unfavorably, it is expected that additional assessments for the years 1999 through September 30, 2002 would be made on the same issue.

Any additional taxes would result in an adjustment to the deferred tax liability with no effect on net income, while any payment of interest or penalties would affect net income. Aquila Gas Pipeline expects that the ultimate resolution of this matter will not have a material adverse effect on its financial position. Under the Asset Purchase Agreement between Aquila and La Grange Acquisition, La Grange Acquisition would not be impacted by resolution of this matter.

Contingencies

In 1996, Aquila Gas Pipeline and Exxon entered into a contract, which required Aquila Gas Pipeline to pay Exxon $5.1 million in 2006 if Aquila Gas Pipeline failed to deliver natural gas containing at least 2 gallons per mcf to the Exxon Katy Plant. In 2000, the determination was made that it was unlikely that the Company would be in a position to supply natural gas that would meet the contract specifications. Included in operating expenses in 2000 was an accrual of $3.6 million representing the present value of the future settlement. In 2001, the Company reached an agreement with Exxon to cancel the contract for a cash settlement of $3.7 million and the exchange of property for right-of-way.

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AQUILA GAS PIPELINE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The Company was also a party to additional claims and was involved in various other litigation and administrative proceedings arising in the normal course of business. Aquila Gas Pipeline believed it was unlikely that the final outcome of any of the claims, litigation or proceedings to which it was a party would have a material adverse effect on its financial position or results of operations. However, due to the inherent uncertainty of litigation, there can be no assurance that the resolution of any particular claim or proceeding would not have an adverse effect on the Company s results of operations for the fiscal period in which such resolution occurred. Per the Asset Purchase Agreement between Aquila and La Grange Acquisition, Aquila has agreed to indemnify La Grange Acquisition for any litigation arising from operations before October 1, 2002.

In the normal course of business of its natural gas pipeline operations, the Company purchased, processed and sold natural gas pursuant to long-term contracts. Such contracts contained terms, which were customary in the industry. The Company believes that such terms were commercially reasonable and will not have a material adverse effect on its financial position or results of operations.

8. Commodity Risk Management

The following table details information on the Company s positions held or issued for trading purposes as of:

September 30, 2002

	Commodity	Notional Volume Bcf	Maturity	Aquila Pays	Aquila Receives	Fair Value
Basis Swaps						
EPNG Permian	Gas	0.4	2002	Nymex	IFERC	$ (142)
EPNG Permian	Gas	0.4	2002	IFERC	Nymex	143
Waha	Gas	3.3	2005	Nymex	IFERC	(711)
Waha	Gas	4.1	2005	IFERC	Nymex	826
Houston Ship	Gas	0.6	2005	Nymex	IFERC	(40)
Houston Ship	Gas	0.6	2005	IFERC	Nymex	44
EPNG Permian	Gas	1.5	2003	Nymex	IFERC	(723)
EPNG Permian	Gas	1.5	2003	IFERC	Nymex	731
EPNG San Juan	Gas		2002	Nymex	IFERC	(456)
EPNG San Juan	Gas		2002	IFERC	Nymex	714
Houston Ship	Gas	101.3	2005	Nymex	IFERC	(1,038)
Houston Ship	Gas	96.7	2005	IFERC	Nymex	1,076
Katy	Gas		2002	Nymex	IFERC	(89)
Katy	Gas		2002	IFERC	Nymex	94
TGP TX	Gas		2002	Nymex	IFERC	(36)
TGP TX	Gas		2002	IFERC	Nymex	16
SOCAL	Gas	1.5	2003	Nymex	IFERC	(428)
SOCAL	Gas	1.5	2003	IFERC	Nymex	174
TETC OLPO STX	Gas	13.6	2005	Nymex	IFERC	274

TETC OLPO STX	Gas	11.7	2005	IFERC	Nymex	(130)
Waha	Gas	97.1	2003	Nymex	IFERC	(8,617)
Waha	Gas	97.1	2003	IFERC	Nymex	8,531

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AQUILA GAS PIPELINE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Buyer/ Seller	Commodity	Notional Volume Bcf	Maturity	Average Strike Price	Fair Value
Futures						
	Buyer	Gas	0.3	2002	3.203	$ (121)
	Seller	Gas	1.1	2002	2.685	(1,086)
	Buyer	Gas	115.9	2005	3.733	29,518
	Seller	Gas	114.3	2005	3.730	(29,729)
	Buyer	Gas	2.5	2002	3.150	679
	Seller	Gas	3.4	2002	2.995	(810)
Forwards						
	Buyer	Gas	181.0	2020	2.919	(3,683)
	Seller	Gas	339.7	2020	3.686	6,570
	Buyer	Transport	15.3	2004	0.029	(12)

	Buyer/ Seller	Commodity	Barrels in Thousands	Maturity	Average Strike Price	Fair Value
NGLs Futures						
	Seller	Ethane	150	2002	0.215	$ 194
	Buyer	Ethane	150	2002	0.265	121
	Seller	Propane	75	2002	0.373	265
	Buyer	Propane	135	2002	0.406	(287)
	Seller	Crude	(254)	2002	29.552	(1,374)

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AQUILA GAS PIPELINE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The net gain from derivative activities for the periods ended September 30, 2002 and December 31, 2001 was $6,273 and $9,016, respectively.

9. Financial Instruments

The Company s carrying amounts for cash and cash equivalents, accounts receivable, other current assets, accounts payable and other current liabilities approximated fair value. The fair values of its derivative positions are disclosed in Note 8. The following summarizes the Company s carrying value and estimated fair value of its long-term debt obligations:

	September 30, 2002	
	Carrying Value	Fair Value
	(In thousands)	
6.83% Loan	$16,250	$19,123
6.47% Loan	50,000	55,751
Total	$66,250	$74,874

AQUILA GAS PIPELINE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

10. Intangible Assets

The following table details the items included in intangible assets:

	Period Ended September 30, 2002
	(In thousands)
Goodwill	$ 9,491
Less: amortization	(7,837)
	1,654
Oasis transportation rights	18,620

Less: amortization	(15,905)
	2,715
Gathering producer relationship	14,930
Less: amortization	(14,081)
	849
Senior note deferred financing costs	
Less: amortization	
Intangibles, net	$ 5,218

Effective January 1, 2002, in accordance with Statements of Financial Accounting Standards No. 141 and No. 142, the Company ceased amortizing its goodwill. Further, the Company concluded that the carrying value of the goodwill was not impaired. Goodwill amortization was $900 in 2001. Amortization expense, excluding goodwill amortization, was $3,644 and $5,031 in September 30, 2002 and December 31, 2001, respectively.

At September 30, 2002, the estimated five-year amortization of the Oasis Pipe Line transportation rights and gathering producer relationships was as follows:

	(In thousands)
Remainder of 2002	$ 840
2003	1,990
2004	91
2005	91
2006	91
2007	91
Thereafter	370
	$3,564

The Oasis Pipe Line transportation rights was an agreement between Aquila Gas Pipeline and Oasis Pipe Line whereby Aquila Gas Pipeline could elect to reserve a portion of Oasis Pipe Line s line capacity in advance. The agreement has been amended numerous times, and under the most recent amendment it was cancelable by either party upon ninety days notice and it was scheduled to expire in July 2003. The gathering producer relationships related to certain fixed price gathering contracts that were being amortized over ten years.

11. Investment in Subsidiaries

Oasis Pipe Line

Prior to December 2000, Aquila Gas Pipeline had a 35% interest in Oasis Pipe Line. Thereafter, Aquila Gas Pipeline held 50% of the stock of Oasis Pipe Line. The following table presents financial information related to Oasis Pipe Line for the periods presented:

	Period Ended	
	September 30, 2002	December 31, 2001
	(In thousands)	
Revenues	$24,733	$26,153
Total operating expenses	7,772	11,266
Income before income tax expense	16,700	14,707
Net income	10,850	9,556
Pipeline s share of net income	5,425	4,778
Pipeline s share of distributions	4,000	1,500
Current assets	10,680	7,061
Total assets	53,929	50,453
Current liabilities	3,893	1,911
Long-term debt		
Shareholder s equity	41,912	39,062

At September 30, 2002, Aquila Gas Pipeline s investment exceeded its pro-rata share of Oasis Pipe Line s equity by $79,792. Prior to 2002, the excess purchase price was being amortized $1,650 per year. In accordance with Aquila Gas Pipeline s adoption of Statement of Financial Accounting Standards No. 141 and 142, this amortization was ceased effective January 1, 2002.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Oasis Pipe Line Company

We have audited the accompanying consolidated balance sheet of Oasis Pipe Line Company and Subsidiaries as of December 27, 2002, and the related consolidated statement of income, shareholders equity and cash flow for the period then ended. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the 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 audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Oasis Pipe Line Company and Subsidiaries as of December 27, 2002, and the consolidated results of its operations and its cash flows for the period then ended in conformity with U.S. generally accepted accounting principles.

/s/ ERNST & YOUNG LLP

San Antonio, Texas
July 15, 2003

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OASIS PIPE LINE COMPANY AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(in thousands)

	December 27, 2002	December 31, 2001
	(unaudited)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 7,962	$ 2,352
Accounts receivable trade (net of allowance for doubtful accounts of $153 in 2002 and $60 in 2001)	2,290	1,997
Accounts receivable affiliates	364	552
Inventories	1,215	1,351
Refundable income taxes		540
Prepaid insurance	325	269
Total current assets	12,156	7,061
Property, plant, and equipment:		
Pipeline facilities	169,308	168,745
Construction-in-progress		119
Less accumulated depreciation and amortization	(127,231)	(125,472)
Property, plant, and equipment, net	42,077	43,392
Other	413	
Total assets	$ 54,646	$ 50,453
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities:		
Accounts payable trade	$ 264	$ 230
Accounts payable affiliates		13
Accrued liabilities	376	385
Accrued taxes	820	
Accrued taxes, other than income taxes		783
Accrued compensation	586	500
Total current liabilities	2,046	1,911
Deferred income taxes	9,461	9,480
Commitments and contingencies		

Shareholders equity:		
Common stock, $1 par value; 50,000 shares authorized and 6,667 shares outstanding	7	7
Additional paid-in capital	25,432	25,432
Retained earnings	35,537	31,460
	60,976	56,899
Less treasury stock, 2,000 shares	17,837	17,837
Total shareholders equity	43,139	39,062
Total liabilities and shareholders equity	$ 54,646	$ 50,453

See accompanying notes.

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OASIS PIPE LINE COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME
(in thousands)

	Period Ended December 27, 2002	Year Ended December 31, 2001
Operating revenues:		
Gas transportation third party	$23,490	$15,749
Gas transportation affiliates	5,975	8,364
Proceeds from pipeline construction		
Gas sales third party	2,352	883
Fuel and unaccounted for gas		763
Other	914	394
Total operating revenues	32,731	26,153
Operating expenses:		
Fuel and unaccounted for gas	133	
Operations and maintenance	4,469	4,325
Cost of pipeline construction		
Depreciation and amortization	2,106	2,458
Taxes, other than income	1,207	1,171
Administrative and general	2,555	3,312
Total operating expenses	10,470	11,266
Operating income	22,261	14,887
Other income (expenses):		
Interest income	64	193
Interest expense shareholder		(433)
Other, net	(660)	60
Income before income taxes	21,665	14,707
Income tax expense	7,588	5,151
Net income	$14,077	$ 9,556

See accompanying notes

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OASIS PIPE LINE COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS EQUITY
Period Ended December 27, 2002 and Year Ended December 31, 2001
(unaudited as to December 31, 2001 data)

	Common Stock		Treasury Stock		Additional Paid-In Capital	Retained Earnings	Total
	Shares	Amount	Shares	Amount			
	(In thousands, except share data)						
Balance at December 31, 2000	6,667	7	2,000	(17,837)	25,432	24,904	32,506
Net income						9,556	9,556
Dividends paid ($.45 per share)						(3,000)	(3,000)
Balance at December 31, 2001	6,667	7	2,000	(17,837)	25,432	31,460	39,062
Net income						14,077	14,077
Dividends paid ($1.50 per share)						(10,000)	(10,000)
Balance at December 27, 2002	6,667	$ 7	2,000	$(17,837)	$25,432	$ 35,537	$ 43,139

See accompanying notes

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OASIS PIPE LINE COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Period Ended December 27, 2002	Year Ended December 31, 2001
		(unaudited)
Operating Activities		
Net income	$ 14,077	$ 9,556
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	2,106	2,458
Deferred income taxes	(19)	213
Changes in assets and liabilities that provided (used) cash:		
Accounts receivable	(105)	(1,744)
Inventories	136	120
Refundable income taxes	540	488
Accounts payable	21	(340)
Accrued liabilities	114	96
Other, net	(469)	3
Net cash provided by operating activities	16,401	10,850
Investing Activities		
Additions to property, plant, and equipment, net	(791)	(511)
Sale of property, plant, and equipment		5
Net cash used in investing activities	(791)	(506)
Financing Activities		
Repayment of notes payable related parties		(11,832)
Dividends paid	(10,000)	(3,000)
Note issued to purchase treasury stock		
Purchase of treasury stock		
Net cash used in financing activities	(10,000)	(14,832)
Increase (decrease) in cash and cash equivalents	5,610	(4,488)
Cash and cash equivalents, beginning of year	2,352	6,840

Cash and cash equivalents, end of year	$ 7,962	$ 2,352
Supplemental cash flow information:		
Cash paid for income taxes	$ 7,080	$ 4,450
Cash paid for interest		433

See accompanying notes

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OASIS PIPE LINE COMPANY AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
Period Ended December 27, 2002 and Year Ended December 31, 2001
(unaudited as to December 31, 2001 data)

1. Control and Ownership of the Company and Related-Party Transactions

Oasis Pipe Line Company (the Company), a Delaware corporation, is engaged in the operation of an intrastate natural gas transmission system in the state of Texas. Immediately prior to December 27, 2002, the Company was owned 50% by a subsidiary of Aquila Gas Pipeline Corporation (Aquila Gas Pipeline), and 50% by Dow Hydrocarbons & Resources, Inc. (DHRI). Prior to October 4, 2002, Aquila Gas Pipeline was the wholly owned subsidiary of Aquila, Inc. In October 2002, La Grange Acquisition, L.P. (La Grange Acquisition) acquired substantially all the assets of Aquila Gas Pipeline. On December 27, 2002 the Company redeemed all of DHRI s stock using funds advanced from La Grange Acquisition making the Company a wholly owned subsidiary of La Grange Acquisition.

Before December 28, 2000, ownership was 35% by a subsidiary of Aquila Gas Pipeline, 35% by El Paso Field Services (EPFS), and 30% by DHRI. On that date, EPFS sold 5% of its interest to DHRI and the remaining 30% interest was acquired by the Company as treasury stock.

During 2002, and 2001, the Company derived revenues from its shareholders and their affiliates for the transmission and sale of natural gas. The amount of such net revenues totaled approximately $5,975,000, and $8,364,000, for the years ended December 27, 2002, and December 31, 2001, respectively. Accounts receivable due from affiliates were approximately $364,000 and $552,000 for 2002 and 2001, respectively.

During 2000, the Company reacquired 2,000 previously issued shares of capital stock for $17.8 million. The acquisition was funded with working capital and the borrowing of $11.8 million from shareholders (Aquila Gas Pipeline and DHRI). The borrowings were represented by notes payable bearing interest at 9%. Interest expense associated with the notes payable was $433,000 during 2001. The notes were paid during 2001.

2. Summary of Significant Accounting Policies

Principles of Consolidation

The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries (collectively, the Company). All intercompany accounts and transactions have been eliminated in consolidation. The consolidated financial statements present the financial position and results of operations of the Company prior to its becoming a subsidiary of La Grange Acquisition and therefore exclude the purchase adjustments relating to the redemption and intercompany promissory note on December 27, 2002 (see Note 7).

Inventories

The Company requires its customers to provide additional gas, based on predetermined quantities of gas to be delivered, for fuel. If the gas is in excess of the Company s needs, the Company can retain the excess gas or sell it to third parties. If additional fuel is required, the Company will purchase additional volumes in the market. Inventories represent the gas that is retained. The Company values inventories at the lower of cost or market as of the balance sheet dates.

OASIS PIPE LINE COMPANY AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Property, Plant, and Equipment

Normal maintenance that does not add capacity or extend the useful life of the equipment and repairs of property, plant, and equipment are charged to expense as incurred. Improvements that materially extend the useful lives of the assets are capitalized, and the assets replaced, if any, are retired. When capital assets are retired or replaced, the balance of the assets and the accumulated depreciation are removed and any gain or loss upon disposition is included in income. Fixed assets of approximately $346,000 and $134,000 were retired during 2002 and 2001, respectively.

Depreciation is computed using the straight-line method of accounting over the estimated useful lives of the related assets. Annual depreciable lives range from 5 to 85 years.

The Company records impairment losses on long-lived assets used in operations when events and circumstances indicate that the assets might be impaired and the undiscounted cash flows estimated to be generated by those assets are less than the carrying amounts of those assets.

Environmental Expenditures

Environmental related restoration and remediation costs are recorded as liabilities and expensed when site restoration and environmental remediation and cleanup obligations are either known or considered probable and the related costs can be reasonably estimated.

Income Taxes

The Company recognizes deferred tax assets and liabilities for the expected future tax consequences of temporary differences between the financial accounting bases and the tax bases of assets and liabilities. The deferred tax effects of these temporary differences are calculated using the tax rates currently in effect.

Revenue Recognition

Transportation revenue is recognized as transportation is provided. Capacity payments are recognized when earned in the period capacity was made available.

Financial Instruments and Credit Risk

The Company s financial instruments consist of cash and cash equivalents, accounts receivable, and accounts payable. The carrying value of the Company s financial instruments approximates fair value due to their short-term nature. The Company considers all investments with maturities of three months or less at acquisition to be cash equivalents. The Company s receivables are generally from entities involved in the energy industry or significant industrial customers. The Company specifically reviews all its receivables in determining its allowance for doubtful accounts and the receivables are generally unsecured.

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OASIS PIPE LINE COMPANY AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Use of Estimates

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

Reclassifications

Certain reclassifications have been made to the 2001 and 2000 amounts to conform to the 2002 presentation.

3. Income Taxes

Components of income tax provision/(benefit) attributable to income before taxes are as follows:

	December 27, 2002	December 31, 2001
Current	$ 7,607	$ 4,938
Deferred	(19)	213
Total income tax expense	$ 7,588	$ 5,151

The tax provision effective rate for December 27, 2002 and December 31, 2001 was 35%.

Deferred income taxes consist of the following:

	December 27, 2002	December 31, 2001
Property, plant and equipment	$ (9,178)	$ (9,131)
Other	(283)	(349)
Net deferred tax liabilities	$ (9,461)	$ (9,480)

4. Employee Benefit Plan

An employee savings plan is available to all permanent employees, effective the first day of their employment. For every $1 each employee contributes, the Company matches $1, not to exceed 5% of each employee s salary subject to the maximum contribution allowed by law. Each employee is fully vested on his or her first day of employment. The Company expensed contributions of approximately $144,000 and $140,000 for 2002 and 2001, respectively.

5. Contingencies

The Company is subject to federal, state and local environmental laws and regulations, which generally require expenditures for remediation at operating facilities and waste disposal sites. At December 27, 2002 and December 31, 2001, the Company had reserved approximately $252,000 and $292,000 respectively, for the expected costs of complying with such laws and regulations. These expected costs are primarily related to properties previously owned and are recorded on the consolidated balance sheets as accrued liabilities based upon management s estimates of the timing of the expenditure. The purchase and sale agreement between La Grange

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OASIS PIPE LINE COMPANY AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Acquisition and Aquila Gas Pipeline requires Aquila, Inc. to reimburse Oasis for 50% of any remediation expenditures related to operations prior to October 1, 2002.

On June 16, 2003, Guadalupe Power Partners, L.P. (GPP) sought and obtained a Temporary Restraining Order against Oasis Pipe Line. In their pleadings, GPP alleged unspecified monetary damages for the period from February 25, 2003 to June 16, 2003 and sought to prevent Oasis Pipe Line from implementing flow control measures to reduce the flow of gas to their power plant at varying hourly rates. Oasis Pipe Line filed a counterclaim against GPP asking for damages and a declaration that the contract was terminated as a result of the breach by GPP. Oasis Pipe Line and GPP agreed to a stand still order and referred this dispute to binding arbitration. Oasis Pipe Line has retained trial counsel to defend this matter and a date for the commencement of the arbitration proceedings has not yet been set.

The Company is also party to legal actions that have arisen in the ordinary course of its business. Due to the inherent uncertainty of litigation, the range of any possible loss cannot be estimated with a reasonable degree of precision.

6. Stock Redemption

On December 27, 2002, the Company purchased 50% of its capital stock owned by DHRI for $87 million. The Company funded the acquisition by borrowing $87 million from La Grange Acquisition evidenced by a promissory note (the Note). Effective with the redemption, the Company became a wholly owned subsidiary of La Grange Acquisition and is included in the financial statements of La Grange Acquisition effective December 27, 2002. The Note bears interest at an annual rate of 8.5% with payments of $1.6 million due monthly until final maturity on February 1, 2006 at which time the remaining balance will be due. The consolidated financial statements present the financial position and results of operations of the Company prior to its becoming a subsidiary of LaGrange Acquisition and therefore exclude the purchase adjustments relating to the redemption and intercompany promissory

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Partners
Energy Transfer Partners, L.P.

We have audited the accompanying consolidated balance sheet of Heritage Propane Partners, L.P. (a Delaware limited partnership) and subsidiaries as of August 31, 2003 and the related consolidated statements of operations, comprehensive income, partners capital, and cash flows for the period ended January 19, 2004 and for the years ended August 31, 2003 and 2002. 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 audit.

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 Heritage Propane Partners, L.P. and subsidiaries as of August 31, 2003 and the results of their operations and their cash flows for the period ended January 19, 2004 and for the years ended August 31, 2003 and 2002, in conformity with accounting principles generally accepted in the United States of America.

As explained in Note 2 to the consolidated financial statements, effective September 1, 2002, the Partnership changed its method of accounting for stock-based compensation plans and adopted the fair value recognition provisions of Statement of Financial Accounting Standards No. 123, Accounting for Stock-Based Compensation following the modified prospective method of adoption described in Statement of Financial Accounting Standards No. 148, Accounting for Stock-Based Compensation Transition and Disclosure.

/s/ Grant Thornton LLP

Tulsa, Oklahoma
November 11, 2004

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HERITAGE PROPANE PARTNERS, L.P. AND SUBSIDIARIES
(HERITAGE)

CONSOLIDATED BALANCE SHEET
(in thousands, except unit data)

	August 31, 2003
ASSETS	
CURRENT ASSETS:	
Cash and cash equivalents	$ 7,117
Marketable securities	3,044
Accounts receivable, net of allowance for doubtful accounts	35,879
Inventories	45,274
Assets from liquids marketing	83
Prepaid expenses and other	2,741
Total current assets	94,138
PROPERTY, PLANT AND EQUIPMENT, net	426,588
INVESTMENT IN AFFILIATES	8,694
GOODWILL	156,595
INTANGIBLES AND OTHER ASSETS, net	52,824
Total assets	$738,839
LIABILITIES AND PARTNERS CAPITAL	
CURRENT LIABILITIES:	
Working capital facility	$ 26,700
Accounts payable	43,690
Accounts payable to related companies	6,255
Accrued and other current liabilities	35,993
Liabilities from liquids marketing	80
Current maturities of long-term debt	38,309
Total current liabilities	151,027
LONG-TERM DEBT, less current maturities	360,762
MINORITY INTERESTS	4,002
	515,791

COMMITMENTS AND CONTINGENCIES	
PARTNERS CAPITAL:	
Common Unitholders (18,013,229 units issued and outstanding)	221,207
Class C Unitholders (1,000,000 units issued and outstanding)	
General Partner	2,190
Accumulated other comprehensive loss	(349)
Total partners capital	223,048
Total liabilities and partners capital	$738,839

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

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HERITAGE PROPANE PARTNERS, L.P. AND SUBSIDIARIES
(HERITAGE)

CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per unit and unit data)

	For the Period Ended January 19, 2004	For the Years Ended August 31, 2003	For the Years Ended August 31, 2002
REVENUES:			
Retail fuel	$ 221,459	$ 463,392	$ 365,334
Wholesale fuel	20,596	47,366	41,204
Liquids marketing, net	369	1,333	542
Other	27,928	59,385	55,245
Total revenues	270,352	571,476	462,325
COSTS AND EXPENSES:			
Cost of products sold	148,329	297,156	238,185
Operating expenses	60,735	152,131	133,203
Depreciation and amortization	15,389	37,959	36,998
Selling, general and administrative	10,100	14,037	12,978
Total costs and expenses	234,553	501,283	421,364
OPERATING INCOME	35,799	70,193	40,961
OTHER INCOME (EXPENSE):			
Interest expense	(12,754)	(35,740)	(37,341)
Equity in earnings of affiliates	496	1,371	1,338
Gain (loss) on disposal of assets	(240)	430	812
Other	(66)	(3,213)	(294)
INCOME BEFORE MINORITY INTERESTS AND INCOME TAXES	23,235	33,041	5,476
Minority interests	(572)	(876)	(574)
NET INCOME BEFORE INCOME TAXES	22,663	32,165	4,902
Income taxes	20	1,023	

NET INCOME	22,643	31,142	4,902
GENERAL PARTNER S INTEREST IN NET INCOME	551	1,319	918
LIMITED PARTNERS INTEREST IN NET INCOME	$ 22,092	$ 29,823	$ 3,984
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 1.21	$ 1.79	$ 0.25
BASIC AVERAGE NUMBER OF UNITS OUTSTANDING	18,286,352	16,635,966	15,738,621
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 1.21	$ 1.79	$ 0.25
DILUTED AVERAGE NUMBER OF UNITS OUTSTANDING	18,333,036	16,694,343	15,777,307

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

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HERITAGE PROPANE PARTNERS, L.P. AND SUBSIDIARIES (HERITAGE)

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in thousands)

	For the Period Ended January 19, 2004	For the Years Ended August 31, 2003	For the Years Ended August 31, 2002
Net income	$ 22,643	$31,142	$ 4,902
Other comprehensive income (loss)			
Reclassification adjustment for losses or gains on derivative instruments included in net income		(553)	
Reclassification adjustment for losses on available-for-sale securities included in net income		2,823	
Change in value of derivative instruments		553	4,464
Change in value of available-for-sale securities	(533)	480	(1,575)
Comprehensive income	$ 22,110	$34,445	$ 7,791
Reconciliation of Accumulated Other Comprehensive Loss			
Balance, beginning of period	$ (349)	$ (3,652)	$(6,541)
Current period reclassification to earnings		2,270	7,016
Current period change	(533)	1,033	(4,127)
Balance, end of period	$ (882)	$ (349)	$(3,652)

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

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HERITAGE PROPANE PARTNERS, L.P. AND SUBSIDIARIES
(HERITAGE)

CONSOLIDATED STATEMENTS OF PARTNERS CAPITAL
(in thousands, except unit data)

	Number of Units			
	Common	**Class B Subordinated**	**Class C**	**Common**
Balance, August 31, 2001	14,260,316	1,382,514	1,000,000	$190,548
Unit distribution				(38,159)
Conversion of Phantom Units	11,750			
Conversion of Subordinated Units	1,382,514	(1,382,514)		15,137
Issuance of units upon conversion of minority interest	162,913			1,729
General Partner capital contribution	(1,646)			(32)
Net change in accumulated other comprehensive loss per accompanying statements				
Other				1,821
Net income				2,633
Balance, August 31, 2002	15,815,847		1,000,000	173,677
Unit distribution				(42,042)
Issuance of Common Units	1,610,000			44,547
Conversion of Phantom Units	2,500			
Issuance of Common Units in connection with the Long-term incentive plan	66,118			
Issuance of Common Units in connection with certain acquisitions	551,456			15,000
General Partner capital contribution	(32,692)			(957)
Net change in accumulated other comprehensive loss per accompanying statements				
Other				1,159
Net income				29,823
Balance, August 31, 2003	18,013,229		1,000,000	221,207
Unit distribution				(23,696)
Conversion of Phantom Units	14,800			
Issuance of Common Units in connection with certain acquisitions	505,826			17,116
General Partner capital contribution				

Net change in accumulated other comprehensive loss per accompanying statements				
Other				1,232
Net income				22,092
Balance, January 19, 2004	18,533,855		1,000,000	$237,951

[Additional columns below]

[Continued from above table, first column(s) repeated]

	Class B Subordinated	**Class C**	**General Partner**	**Accumulated Other Comprehensive Income (Loss)**	**Total**
Balance, August 31, 2001	$ 15,532	$	$ 1,875	$ (6,541)	$201,414
Unit distribution	(1,746)		(1,240)		(41,145)
Conversion of Phantom Units					
Conversion of Subordinated Units	(15,137)				
Issuance of units upon conversion of minority interest					1,729
General Partner capital contribution			32		
Net change in accumulated other comprehensive loss per accompanying statements				2,889	2,889
Other					1,821
Net income	1,351	—	918		4,902
Balance, August 31, 2002			1,585	(3,652)	171,610
Unit distribution			(1,342)		(43,384)
Issuance of Common Units					44,547
Conversion of Phantom Units					
Issuance of Common Units in connection with the Long-term incentive plan					
Issuance of Common Units in connection with certain acquisitions					15,000
General Partner capital contribution			628		(329)
Net change in accumulated other comprehensive loss per accompanying statements				3,303	3,303

Other					1,159
Net income			1,319		31,142
Balance, August 31, 2003			2,190	(349)	223,048
Unit distribution			(887)		(24,583)
Conversion of Phantom Units					
Issuance of Common Units in connection with certain acquisitions					17,116
General Partner capital contribution			180		180
Net change in accumulated other comprehensive loss per accompanying statements				(533)	(533)
Other					1,232
Net income			551		22,643
Balance, January 19, 2004	$	$	$ 2,034	$ (882)	$239,103

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

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HERITAGE PROPANE PARTNERS, L.P. AND SUBSIDIARIES
(HERITAGE)

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	For the Period Ended January 19, 2004	For the Years Ended August 31, 2003	For the Years Ended August 31, 2002
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 22,643	$ 31,142	$ 4,902
Reconciliation of net income to net cash provided by operating activities-			
Depreciation and amortization	15,389	37,959	36,998
Provision for loss on accounts receivable	449	2,578	887
Loss on write down of marketable securities		2,823	
(Gain) loss on disposal of assets	240	(430)	(812)
Deferred compensation on restricted units and long- term incentive plan	1,232	1,159	1,878
Undistributed earnings of affiliates	(35)	(836)	(938)
Minority interests	491	(48)	(111)
Changes in assets and liabilities, net of effect of acquisitions:			
Accounts receivable	(29,745)	(4,066)	9,180
Inventories	(37,850)	4,855	17,827
Assets from liquids marketing	82	2,218	4,164
Prepaid and other expenses	(6,262)	4,177	8,086
Intangibles and other assets	(2,019)	238	1,197
Accounts payable	56,296	3,115	(4,094)
Accounts payable to related companies	(6,620)	1,253	(2,935)
Accrued and other current liabilites	555	10,800	(5,464)
Liabilities from liquids marketing	(80)	(1,738)	(5,312)
Net cash provided by operating activities	14,766	95,199	65,453
CASH FLOWS FROM INVESTING ACTIVITIES:			
Cash paid for acquisitions, net of cash acquired	(22,490)	(24,956)	(19,742)
Capital expenditures	(19,760)	(27,294)	(27,072)
Proceeds from the sale of assets	772	3,861	13,336
Investment in marketable securities			(29)
Other			95
Net cash used in investing activities	(41,478)	(48,389)	(33,412)

CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from borrowings	239,359	173,678	164,715
Principal payments on debt	(170,539)	(219,282)	(156,584)
Net proceeds from issuance of Common Units		44,547	
Unit distributions	(24,583)	(43,384)	(41,145)
Other	180	152	(57)
Net cash provided by (used in) financing activities	44,417	(44,289)	(33,071)
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	17,705	2,521	(1,030)
CASH AND CASH EQUIVALENTS, beginning of period	7,117	4,596	5,626
CASH AND CASH EQUIVALENTS, end of period	$ 24,822	$ 7,117	$ 4,596

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HERITAGE PROPANE PARTNERS, L.P. AND SUBSIDIARIES
(HERITAGE)

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	For the Period Ended January 19, 2004	For the Years Ended August 31, 2003	For the Years Ended August 31, 2002
NONCASH FINANCING ACTIVITIES:			
Notes payable incurred on noncompete agreements	$ 6,914	$ 948	$ 2,737
Issuance of Common Units in connection with certain acquisitions	$ 17,116	$ 15,000	$
Issuance of Common Units upon conversion of minority interest	$	$	$ 1,729
General Partner capital contribution	$	$ 329	$
Conversion of equity investment in Bi State Partnership to wholly owned subsidiary upon purchase of remaining 50% that was not previously owned by Heritage	$ 8,249	$	$
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:			
Cash paid during the period for interest	$ 12,261	$ 35,315	$ 37,610
Cash paid during the period for income taxes	$ 46	$ 523	$

The accompanying notes are an integral part of these financial statements

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HERITAGE PROPANE PARTNERS, L.P. AND SUBSIDIARIES
(HERITAGE)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollar amounts in thousands, except unit and per unit data)

1. OPERATIONS AND ORGANIZATION:

Energy Transfer Transactions

On January 20, 2004, Heritage Propane Partners, L.P., (Heritage) and La Grange Energy, L.P. (La Grange Energy) completed the series of transactions whereby La Grange Energy 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 of $300,000 less the amount of Energy Transfer Company debt in excess of $151,500, less ETC OLP s accounts payable and other specified liabilities, plus agreed upon capital expenditures paid by La Grange Energy relating to the ETC OLP business prior to closing, $433,909 of Heritage Common and Class D Units, and the repayment of the ETC OLP debt of $151,500. 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 La Grange Energy and an affiliate of La Grange Energy contributed an office building to ETC OLP. La Grange Energy also received 3,742,515 Special Units as consideration for the project it had in progress to construct the Bossier Pipeline.

Simultaneously with the Energy Transfer Transactions, La Grange Energy obtained control of Heritage by acquiring all of the interest in U.S. Propane, L.P., (U.S. Propane) the General Partner of Heritage, and U.S. Propane, L.P. s general partner, U.S. Propane, L.L.C., from subsidiaries of AGL Resources, Atmos Energy Corporation, TECO Energy, Inc. and Piedmont Natural Gas Company, Inc. for $30,000 (the General Partner Transaction). In conjunction with the General Partner Transaction, U.S. Propane L.P. contributed its 1.0101% General Partner interest in Heritage Operating, L.P. (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 $100,000.

Concurrent with the Energy Transfer Transactions, La Grange Acquisition borrowed $325,000 from financial institutions and Heritage raised $355,948 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 transaction and for general partnership purposes.

Accounting treatment of the Energy Transfer Transactions

The Energy Transfer Transactions were accounted for as a reverse acquisition in accordance with SFAS 141. Although Heritage Propane Partners, L.P. is the surviving parent entity for legal purposes, ETC OLP is the acquirer for accounting purposes. As a result, ETC OLP s historical financial statements are now the historical financial statements of the registrant. The operations of Heritage Propane Partners, L.P. prior to the ETC OLP Transaction are referred to as Heritage. On February 12, 2004, the Board of Directors of Heritage Propane Partners, L.P. s General Partner voted to change the name of Heritage Propane Partners, L.P. to Energy Transfer Partners, L.P. The assets and liabilities and results of operations of Heritage as of January 19, 2004 are included in the financial statements of the surviving parent entity, Energy Transfer Partners, L.P.

Business Operations

In order to simplify the Heritage s obligations under the laws of several jurisdictions in which it conducts business, the Partnership s activities are conducted through a subsidiary operating partnership, Heritage Operating, L.P. (the Operating Partnership). The Partnership and the Operating Partnership are collectively referred to in this report as Heritage. Heritage sells propane and propane-related products to more than 650,000 active residential, commercial, industrial, and agricultural customers from over 310 customer service locations in 32 states. Heritage is also a wholesale propane supplier in the United States and in Canada, the latter through participation in MP Energy Partnership. MP Energy Partnership is a Canadian partnership, in which Heritage owns a 60% interest, engaged in lower-margin wholesale distribution and in supplying Heritage s northern U.S. locations. Heritage buys and sells financial instruments for its own account through its wholly owned subsidiary, Heritage Energy Resources, L.L.C. (Resources).

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

Principles of Consolidation

The consolidated financial statements of Heritage include the accounts of its subsidiaries, including Heritage Operating and its subsidiaries. At August 31, 2003, Heritage accounted for its 50% partnership interest in Bi-State Propane, (Bi-State) a propane retailer in the states of Nevada and California, under the equity method. On December 24, 2003, Heritage acquired the remaining 50% of Bi-State that it did not previously own, thereby making Bi-State a wholly owned subsidiary of Heritage.

For purposes of maintaining partner capital accounts, the Partnership Agreement of Heritage (the Partnership Agreement) specifies that items of income and loss shall be allocated among the partners in accordance with their percentage interests. Normal allocations according to percentage interests are made, however, only after giving effect to any priority income allocations in an amount equal to the incentive distributions that are allocated 100% to the General Partner. The 1.0101% general partner interest in the Operating Partnership held by the General Partner, U.S. Propane, L.P. (U.S. Propane), is accounted for in the consolidated financial statements of Heritage as a minority interest.

Revenue Recognition

Sales of propane, 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 is recognized upon completion of the service and tank rent is recognized ratably over the period it is earned. Shipping and handling revenues are included in the price of propane charged to customers, and thus are classified as revenues.

Costs and Expenses

Costs of products sold include actual cost of fuel sold adjusted for the effects of qualifying cash flow hedges, storage fees and inbound freight, 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, purchasing costs, and plant operations. Selling, general and administrative expenses include all corporate expenses and compensation for corporate personnel.

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. Heritage 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

Heritage s marketable securities are classified as available-for-sale securities and are reflected as a current asset on the consolidated balance sheet at their fair value. During the year ended August 31, 2003, Heritage determined there was a non-temporary decline in the market value of its available-for-sale securities, and reclassified into earnings a loss of $2,823, which is net of minority interest and is recorded in other expense. Unrealized holding gains (losses) of $480 and $(1,575) for the years ended August 31, 2003 and 2002, respectively, were recorded through accumulated other comprehensive income (loss) based on the market value of the securities.

Accounts Receivable

Heritage grants credit to its customers for the purchase of propane and propane-related products. Accounts receivable are recorded at amounts billed to customers less an allowance for doubtful accounts. The allowance for doubtful accounts is based on management s assessment of the realizability of customer accounts. Management s assessment is based on the overall creditworthiness of Heritage s customers and any specific disputes. Heritage recorded bad debt expense net of recoveries of $449, $2,578 and $887, for the period ended January 19, 2004 and the years ended August 31, 2003 and 2002, respectively. Accounts receivable consisted of the following:

	August 31, 2003
Accounts receivable	$39,383
Less allowance for doubtful accounts	3,504
Total, net	$35,879

The activity in the allowance for doubtful accounts consisted of the following:

	Period Ended January 19, 2004	Years Ended August 31,	
		2003	2002
Balance, beginning of the period	$ 3,504	$ 2,504	$ 3,576
Provision for loss on accounts receivable	449	2,578	887
Accounts receivable written off, net of recoveries	(449)	(1,578)	(1,959)
Balance, end of period	$ 3,504	$ 3,504	$ 2,504

Inventories

Inventories are valued at the lower of cost or market. The cost of fuel inventories is determined using weighted-average cost of fuel delivered to the retail districts 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:

	August 31, 2003
Fuel	$34,544
Appliances, parts and fittings	10,730
Total inventories	$45,274

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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 are expensed as incurred. Expenditures to refurbish tanks that either extend the useful lives of the tanks or prevent environmental contamination are capitalized and depreciated over the remaining useful life of the tanks. Additionally, Heritage capitalizes certain costs directly related to the installation of company-owned tanks, including internal labor costs. Components and useful lives of property, plant and equipment were as follows:

	August 31, 2003
Land and improvements	$ 21,937
Buildings and improvements (10 to 30 years)	30,843
Bulk storage, equipment and facilities (3 to 30 years)	43,340
Tanks and other equipment (5 to 30 years)	327,193
Vehicles (5 to 10 years)	76,239
Furniture and fixtures (3 to 10 years)	11,164
Other (5 to 10 years)	3,578
	514,294
Less Accumulated depreciation	(99,563)
	414,731
Plus Construction work-in-process	11,857
Property, plant and equipment, net	$426,588

Intangibles and Other Assets

Intangibles and other assets are stated at cost net of amortization computed on the straight-line method. Heritage eliminates from its balance sheet any fully amortized intangibles and the related accumulated amortization. Components and useful lives of intangibles and other assets were as follows:

	August 31, 2003	
	Gross Carrying Amount	Accumulated Amortization
Amortized intangible assets		

Noncompete agreements (5 to 15 years)	$42,742	$(15,893)
Customer lists (15 years)	28,378	(6,356)
Financing costs (3 to 15 years)	4,225	(1,995)
Consulting agreements (2 to 7 years)	517	(367)
Total	75,862	(24,611)
Unamortized intangible assets		
Trademarks	1,309	
Other assets	264	
Total intangibles and other assets	$77,435	$(24,611)

Aggregate amortization expense of intangible assets was $2,927, $7,811, and $8,152 for the period ended January 19, 2004 and the years ended August 31, 2003 and 2002, respectively.

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Goodwill

Goodwill is associated with acquisitions made for Heritage s domestic retail segment; therefore, all goodwill is recorded in this segment. Of the $156,595 balance in goodwill, $23,923 is expected to be tax deductible. Goodwill is tested for impairment at the end of each fiscal year end in accordance with SFAS 142. The changes in the carrying amount of goodwill for the year ended August 31, 2003 were as follows:

Balance as of August 31, 2002	155,735
Goodwill acquired during the year	860
Impairment losses	
Balance as of August 31, 2003	156,595

Long-Lived Assets

Heritage 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, Heritage reduces the carrying amount of such assets to fair value. No impairment of long-lived assets was recorded during the period ended January 19, 2004, or the years ended August 31, 2003 and 2002.

Accrued and Other Current Liabilities

Accrued and other current liabilities consisted of the following:

	August 31, 2003
Interest payable	$ 4,485
Wages and payroll taxes	4,932
Deferred tank rent	4,080
Advanced budget payments and unearned revenue	15,417
Customer deposits	2,137
Taxes other than income	2,405
Income taxes	500
Other	2,037
Accrued and other current liabilities	$35,993

Income Taxes

Heritage is a master limited partnership. As a result, Heritage s earnings or losses for federal and state income tax purposes are included in the tax returns of the individual partners. Accordingly, no recognition has been given to income taxes in the accompanying financial statements of Heritage except those incurred by corporate subsidiaries of Heritage that are subject to income taxes. On May 31, 2003 Guilford Gas Service, Inc., one of the Heritage s taxable subsidiaries was merged with the Operating Partnership. Taxes recorded in connection with this liquidation were approximately $250. 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. As of August 31, 2003 there was a liability of $500 recorded for income taxes incurred by Heritage s corporate subsidiaries.

Income Per Limited Partner Unit

Basic net income per limited partner unit is computed by dividing net income, after considering the General Partner s interest, by the weighted average number of Common Units outstanding. Diluted net income per limited partner unit is computed by dividing net income, after considering the General Partner s interest, by the weighted average number of Common Units outstanding and, if dilutive, the weighted average number of restricted units (Phantom Units) outstanding under the Restricted Unit Plan. A reconciliation of net income and weighted average units used in computing basic and diluted net income per unit is as follows:

	Period Ended January 19, 2004	Years Ended August 31, 2003	Years Ended August 31, 2002
Basic Net Income per Limited Partner Unit:			
Limited Partners interest in net income	$ 22,092	$ 29,823	$ 3,984
Weighted average limited partner units	18,286,352	16,635,966	15,738,621
Basic net income per limited partner unit	$ 1.21	$ 1.79	$ 0.25
Diluted Net Income per Limited Partner Unit:			
Limited partners interest in net income	$ 22,092	$ 29,823	$ 3,984
Weighted average limited partner units	18,286,352	16,635,966	15,738,621
Dilutive effect of phantom units	46,684	58,377	38,686
Weighted average limited partner units, assuming dilutive effect of phantom units	18,333,036	16,694,343	15,777,307
Diluted net income per limited partner unit	$ 1.21	$ 1.79	$ 0.25

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.

Some of the more significant estimates made by management include, but are not limited to, allowances for doubtful accounts, derivative hedging instruments, liquids marketing assets and liabilities, purchase accounting allocations and subsequent realizability of intangible assets, and general business and medical self-insurance reserves. Actual results could differ from those estimates.

Fair Value

The carrying amounts of accounts receivable and accounts payable approximate their fair value. Based on the estimated borrowing rates currently available to Heritage for long-term loans with similar terms and average maturities, the aggregate fair value and carrying amount of long-term debt at August 31, 2003 was $421,579 and $399,071, respectively.

Stock Based Compensation Plans

During the fourth quarter of 2003, Heritage adopted the fair value recognition provisions of Statement of Financial Accounting Standards No. 123 *Accounting for Stock-based Compensation* (SFAS 123) effective as of September 1, 2002. Heritage applied the fair value recognition provisions following the modified prospective method of adoption described in Statement of Financial Accounting Standards No. 148, *Accounting for Stock-Based Compensation Transition and Disclosure* (SFAS 148).

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 grants. Heritage assumed a weighted average risk free interest rate of 6.29% for the period ended January 19, 2004, 5.72% for the year ended August 31, 2003, and 6.18% for the year ended August 31, 2002 in estimating the present value of the future cash flows of the distributions during the vesting period on the measurement date of each grant. Annual average cash distributions at the grant date were estimated to be $2.70 for the period ended January 19, 2004, $2.39 for the year ended August 31, 2003, and $2.37 for the year ended August 31, 2002. The expected life of each grant is assumed to be the minimum vesting period under certain performance criteria of each grant.

Accounting for Derivative Instruments and Hedging Activities

Heritage applies Financial Accounting Standards Board (FASB) Statement No. 133, *Accounting for Derivative Instruments and Hedging Activities* (SFAS 133). SFAS 133 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. There were no such financial instruments outstanding as of August 31, 2003.

Heritage buys and sells derivative financial instruments, which are within the scope of SFAS 133 and that are not designated as accounting hedges. Heritage also enters into energy trading contracts, which are not derivatives, and therefore are not within the scope of SFAS 133. EITF Issue No. 98-10, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities* (EITF 98-10), applied to energy trading contracts not within the scope of SFAS 133 that were entered into prior to October 25, 2002. The types of contracts Heritage utilizes in its liquids marketing segment include energy commodity forward contracts, options, and swaps traded on the over-the-counter financial markets. In accordance with the provisions of SFAS 133, derivative financial instruments utilized in connection with Heritage s liquids marketing activity are accounted for using the mark-to-market method. Additionally, all energy trading contracts entered into prior to October 25, 2002 were accounted for using the mark-to-market method in accordance with the provisions of EITF 98-10. Under the mark-to-market method of accounting, forwards, swaps, options, and storage contracts are reflected at fair value, and are shown in the consolidated balance sheet as assets and liabilities from liquids marketing activities. As of August 31, 2002, Heritage adopted 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 statement of operations as liquids marketing revenue. Changes in the assets and liabilities from the liquids marketing activities result primarily from changes in the market prices, newly originated transactions, and the timing and settlement of contracts. EITF 02-3 also rescinds EITF 98-10 for all energy trading contracts entered into after October 25, 2002 and specifies certain disclosure requirements. Consequently, Heritage does not apply mark-to-market accounting for any contracts entered into after October 25, 2002, that are not within the scope of SFAS 133. Heritage attempts to balance its contractual portfolio in terms of notional amounts and timing of performance and delivery obligations. However, net unbalanced positions can exist or are established based on management s assessment of anticipated market movements.

The notional amounts and terms of these financial instruments as of August 31, 2003 include fixed price payor for 45 barrels of propane and fixed price receiver of 195 barrels of propane, respectively. Notional amounts reflect the volume of the transactions, but do not represent the amounts exchanged by the parties to the financial instruments. Accordingly, notional amounts do not accurately measure Heritage s exposure to market or credit risks.

Estimates related to Resource s liquids marketing activities are sensitive to uncertainty and volatility inherent in the energy commodities markets and actual results could differ from these estimates. A theoretical change of 10% in the underlying commodity value of the liquids marketing contracts would result in an approximate $345 change in the market value of the contracts as there were approximately 6.3 million gallons of net unbalanced positions at August 31, 2003.

Inherent in the resulting contractual portfolio are certain business risks, including market risk and credit risk. Market risk is the risk that the value of the portfolio will change, either favorably or unfavorably, in response to changing market conditions. Credit risk is the risk of loss from nonperformance by suppliers, customers, or financial counterparties to a contract. Heritage and Resources take active roles in managing and controlling market and credit risk and have established control procedures, which are reviewed on an ongoing basis. Heritage monitors

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market risk through a variety of techniques, including routine reporting to senior management. Heritage attempts to minimize credit risk exposure through credit policies and periodic monitoring procedures.

The following table summarizes the fair value of Resources contracts, aggregated by method of estimating fair value of the contracts as of August 31, 2003 where settlement had not yet occurred. Resources contracts all have a maturity of less than 1 year. The market prices used to value these transactions reflect management s best estimate considering various factors including closing average spot prices for the current and outer months plus a differential to consider time value and storage costs.

Source of Fair Value	**August 31, 2003**
Prices actively quoted	$ 80
Prices based on other valuation methods	3
Assets from liquids marketing	$ 83
Prices actively quoted	$ 80
Prices based on other valuation methods	
Liabilities from liquids marketing	$ 80
Unrealized gains (losses)	$ 3

The following table summarizes the changes in the unrealized fair value of Resources contracts where settlement had not yet occurred for the period ended January 19, 2004 and the years ended August 31, 2003 and 2002.

	January 19, 2004	**August 31, 2003**	**August 31, 2002**
Unrealized gains (losses) in fair value of contracts outstanding at the beginning of the period	$ 3	$ 483	$ (665)
Unrealized gains (losses) recognized at inception of contracts			
Unrealized gains (losses) recognized as a result of changes in valuation techniques and assumptions			
Other unrealized gains (losses) recognized during the period	366	850	1,207

Less: Realized gains (losses) recognized during the period	369	1,330	59
Unrealized gains (losses) in fair value of contracts outstanding at the end of the period	$	$ 3	$ 483

The following table summarizes the gross transaction volumes in barrels for liquids marketing contracts that were physically settled for the period ended January 19, 2004 and the years ended August 31, 2003, and 2002:

	(in thousands)
Period ended January 19, 2004	29
Fiscal year ended August 31, 2003	181
Fiscal year ended August 31, 2002	350

3. ACQUISITIONS:

During the period ended January 19, 2004, Heritage acquired the assets of Big Sky Petroleum, Archibald Propane, Moore-L.P. Gas, Inc., Sunbeam L.P., Gas, Inc. Metro Lift Propane, and two other small companies. Heritage also acquired the 50% interest in Bi-State Propane that it did not previously own. The aggregate purchase price for these acquisitions was $47,989 which included $22,490 in cash, $17,116 in Common Units issued, and $8,383 liabilities assumed and non-compete agreements.

On January 2, 2003, Heritage purchased the propane assets of V-1 Oil Co. (V-1) of Idaho Falls, Idaho for total consideration of $35.4 million after post-closing adjustments. The acquisition price was payable $20.0 million in cash, with $17.3 million of that amount financed by the Acquisition Facility, and by the issuance of 551,456 Common Units of Heritage valued at $15.0 million, and assumed $0.4 million in liabilities. V-1 s propane distribution network included 35 customer service locations in Colorado, Idaho, Montana, Oregon, Utah, Washington, and Wyoming. Heritage was able to expand its market presence in the Northwest and achieve a greater geographical balance through the transaction with V-1. This acquisition enhanced Heritage s current operations and reduced costs through synergies with existing operations in locations in which Heritage was already conducting business. The results of operations of V-1 from January 2, 2003 to August 31, 2003 are included in the consolidated statement of operations of Heritage for the year ended August 31, 2003.

The following unaudited pro forma consolidated results of operations are presented as if the acquisition of V-1 had been made at the beginning of the period presented:

	Year ended August 31, 2003	Year ended August 31, 2002
Total revenues	$582,690	$494,805
Limited partners interest in net income	$ 31,430	$ 6,806
Basic net income per limited partner unit	$ 1.89	$ .42
Diluted net income per limited partner unit	$ 1.88	$ .42

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 unaudited 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. The following table summarizes the estimated fair values of the assets acquired and liabilities assumed of V-1 as of the date of acquisition:

Current assets	$ 4,952
Property, plant, & equipment	29,324
Goodwill	20
Customer lists (15 years)	740
Trademarks	370
Total assets acquired	$35,406
Total liabilities assumed	(423)
Net assets acquired	$34,983

Of the total amount assigned to goodwill, $20 is expected to be deductible for tax purposes.

During the year ended August 31, 2003, Heritage also acquired substantially all of the assets of four other companies, which included V-1 Oil Company of Spokane, Washington, Stegall Petroleum located in North Carolina, 1st Propane of Boise Idaho, and Love Propane Gas located in South Carolina. Heritage also purchased the stock of Tri-Cities Gas Company, Inc. located in Alabama. The aggregate purchase price for these acquisitions totaled $6.4 million, which included liabilities assumed and non-compete agreements of $1.4 million for periods ranging from five to ten years. In the aggregate, these acquisitions are not material for proforma disclosure purposes. These acquisitions were financed primarily with the acquisition facility and were accounted for by the purchase method under SFAS 141. Heritage has historically accounted for business combinations using the purchase method; therefore, the guidelines of SFAS 141 did not have a significant impact on how Heritage accounted for these acquisitions.

During the year ended August 31, 2002, Heritage purchased the stock of Virginia Gas Propane Company, Inc., in Virginia, Mt. Pleasant Propane, Inc. in Tennessee and two other smaller companies. Heritage also acquired substantially all of the assets of six companies, which included Tri-County Propane, Inc., located in North Carolina, Franconia Gas Corporation located in New Hampshire and Quality Gas, Inc. also located in North Carolina. The aggregate purchase price for these acquisitions totaled $24,915, which included liabilities assumed and non-compete agreements of $5.2 million for periods ranging from five to ten years. In the aggregate, these acquisitions are not material for pro forma disclosure purposes. These acquisitions were financed primarily with the acquisition facility and were accounted for by the purchase method under SFAS 141.

Heritage recorded the following intangible assets in conjunction with these acquisitions as of August 31, 2003:

Customer lists (15 years)	$1,166
Non-compete agreements (5 to 10 years)	769
Total amortized intangible assets	1,935
Trademarks and trade names	381
Goodwill	860
Other assets	
Total intangible assets acquired	$3,176

Goodwill was warranted because these acquisitions enhance Heritage s current operations and certain acquisitions are expected to reduce costs through synergies with existing operations. Heritage assigned all of the goodwill acquired to the retail-operating segment of Heritage. The results of operations from these acquisitions are included on Heritage s statement of operations from the dates acquired.

4. WORKING CAPITAL FACILITY AND LONG-TERM DEBT:

Long-term debt consists of the following:

	August 31, 2003
1996 8.55% Senior Secured Notes	$96,000
1997 Medium Term Note Program:	
7.17% Series A Senior Secured Notes	12,000
7.26% Series B Senior Secured Notes	20,000
6.50% Series C Senior Secured Notes	2,143
2000 and 2001 Senior Secured Promissory Notes:	
8.47% Series A Senior Secured Notes	16,000
8.55% Series B Senior Secured Notes	32,000
8.59% Series C Senior Secured Notes	27,000
8.67% Series D Senior Secured Notes	58,000
8.75% Series E Senior Secured Notes	7,000

8.87% Series F Senior Secured Notes	40,000
7.21% Series G Senior Secured Notes	19,000
7.89% Series H Senior Secured Notes	8,000
7.99% Series I Senior Secured Notes	16,000
Senior Revolving Acquisition Facility	24,700
Notes Payable on noncompete agreements with interest imputed at rates averaging 7.38%, due in installments through 2010, collateralized by a first security lien on certain assets of Heritage	20,110

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	August 31, 2003
Other	1,118
Current maturities of long-term debt	(38,309)
	$360,762

Maturities of the Senior Secured Notes, the Medium Term Note Program and the Senior Secured Promissory Notes are as follows:

1996 8.55% Senior Secured Notes:

mature at the rate of $12,000 on June 30 in each of the years 2002 to and including 2011. Interest is paid semi-annually.

1997 Medium Term Note Program:

Series A Notes: mature at the rate of $2,400 on November 19 in each of the years 2005 to and including 2009. Interest is paid semi-annually.

Series B Notes: mature at the rate of $2,000 on November 19 in each of the years 2003 to and including 2012. Interest is paid semi-annually.

Series C Notes: mature at the rate of $714 on March 13 in each of the years 2000 to and including 2003, $357 on March 13, 2004, $1,073 on March 13, 2005, and $357 in each of the years 2006 and 2007. Interest is paid semi-annually.

2000 and 2001 Senior Secured Promissory Notes:

Series A Notes: mature at the rate of $3,200 on August 15 in each of the years 2003 to and including 2007. Interest is paid quarterly.

Series B Notes: mature at the rate of $4,571 on August 15 in each of the years 2004 to and including 2010. Interest is paid quarterly.

Series C Notes: mature at the rate of $5,750 on August 15 in each of the years 2006 to and including 2007, $4,000 on August 15, 2008 and $5,750 on August 15, 2009 to and including 2010. Interest is paid quarterly.