

Energy Transfer Partners, L.P.  
Form 10-K  
February 22, 2012  
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UNITED STATES  
SECURITIES AND EXCHANGE COMMISSION  
Washington, D.C. 20549  
FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934  
For the fiscal year ended December 31, 2011

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

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.)

3738 Oak Lawn Avenue, Dallas, Texas 75219

(Address of principal executive offices) (zip code)

Registrant's telephone number, including area code: (214) 981-0700

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

Title of each class

Name of each exchange on which registered

Common Units

New York Stock Exchange

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

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

Yes  No

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

Yes  No

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  No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes  No

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer  Accelerated filer  Non-accelerated filer  Smaller reporting company

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

Yes  No

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The aggregate market value as of June 30, 2011, of the registrant's Common Units held by non-affiliates of the registrant, based on the reported closing price of such Common Units on the New York Stock Exchange on such date, was \$7.70 billion. 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 February 15, 2012, the registrant had 226,316,387 Common Units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None

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## PART I

## Forward-Looking Statements

Certain matters discussed in this report, excluding historical information, as well as some statements by Energy Transfer Partners, L.P. (“Energy Transfer Partners” or the “Partnership”) in periodic press releases and some oral statements of the Partnership’s officials during presentations about the Partnership, include “forward-looking” statements. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. Statements using words such as “anticipate,” “believe,” “intend,” “project,” “plan,” “expect,” “continue,” “estimate,” “goal,” “forecast,” “may,” “will” or similar expressions help identify forward-looking statements. Although the Partnership and its general partner believe such forward-looking statements are based on reasonable assumptions and current expectations and projections about future events, no assurance can be given that such assumptions, expectations, or projections will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, the Partnership’s actual results may vary materially from those anticipated, projected, forecasted, estimated or expressed in forward-looking statements since many of the factors that determine these results are subject to uncertainties and risks that are difficult to predict and beyond management’s control. For additional discussion of risks, uncertainties and assumptions, see “Item 1A. Risk Factors” included in this annual report.

## Definitions

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 used by gas companies to convert the volume of gas used to its heat equivalent, and thus calculate the actual energy content
Capacity	capacity of a pipeline, processing plant or storage facility refers to the maximum capacity under normal operating conditions and, with respect to pipeline transportation capacity, is subject to multiple factors (including natural gas injections and withdrawals at various delivery points along the pipeline and the utilization of compression) which may reduce the throughput capacity from specified capacity levels
MMBtu	million British thermal units
MMcf	million cubic feet
Bcf	billion cubic feet
NGL	natural gas liquid, such as propane, butane and natural gasoline
Tcf	trillion cubic feet
LIBOR	London Interbank Offered Rate
NYMEX	New York Mercantile Exchange
Reservoir	a porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers

Adjusted EBITDA is a term used throughout this document, which we define as earnings before interest, taxes, depreciation, amortization and other non-cash items, such as non-cash compensation expense, gains and losses on disposals of assets, the allowance for equity funds used during construction, unrealized gains and losses on commodity risk management activities, non-cash impairment charges, and other non-operating income or expense items. Unrealized gains and losses on commodity risk management activities includes unrealized gains and losses on commodity derivatives and inventory fair value adjustments (excluding lower of cost or market adjustments). Adjusted EBITDA reflects amounts for less than wholly owned subsidiaries and unconsolidated affiliates based on the Partnership's proportionate ownership.

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ITEM 1. BUSINESS

Overview

We (Energy Transfer Partners, L.P., a Delaware limited partnership, “ETP” or the “Partnership”) are one of the largest publicly traded master limited partnerships in the United States in terms of equity market capitalization (approximately \$11.16 billion as of January 31, 2012). We are managed by our general partner, Energy Transfer Partners GP, L.P. (our “General Partner” or “ETP GP”), and ETP GP is managed by its general partner, Energy Transfer Partners, L.L.C. (“ETP LLC”), which is owned by Energy Transfer Equity, L.P., another publicly traded master limited partnership (“ETE”). The activities in which we are engaged, all of which are in the United States, and the wholly-owned operating subsidiaries (collectively referred to as the “Operating Companies”) through which we conduct those activities are as follows:

• Natural gas operations, including the following:

• natural gas midstream and intrastate transportation and storage through La Grange Acquisition, L.P., which conducts business under the assumed name of Energy Transfer Company (“ETC OLP”); and

• interstate natural gas transportation services through Energy Transfer Interstate Holdings, LLC (“ET Interstate”). ET Interstate is the parent company of Transwestern Pipeline Company, LLC (“Transwestern”), ETC Fayetteville Express Pipeline, LLC (“ETC FEP”) and ETC Tiger Pipeline, LLC (“ETC Tiger”).

• NGL transportation, storage and fractionation services primarily through Lone Star NGL LLC (“Lone Star”).

• Retail propane through Heritage Operating, L.P. (“HOLP”) and Titan Energy Partners, L.P. (“Titan”), both of which were contributed to AmeriGas Partners, L.P. (“AmeriGas”) in January 2012 as discussed in “Recent Developments and Current Growth Projects” below.

• Other operations, including natural gas compression services.

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The following chart summarizes our organizational structure as of December 31, 2011:

Unless the context requires otherwise, the Partnership, the Operating Companies, and their subsidiaries are collectively referred to in this report as “we,” “us,” “ETP,” “Energy Transfer” or “the Partnership.”

Significant Achievements in 2011 and Beyond

Our significant 2011 achievements included the following, as discussed in more detail herein:

Formed ETP-Regency Midstream Holdings, LLC (“ETP-Regency LLC”), a joint venture owned 70% by us and 30% by Regency Energy Partners LP (“Regency”), which acquired all of the membership interest in LDH Energy Asset Holdings LLC (“LDH”), a wholly owned subsidiary of Louis Dreyfus Highbridge Energy, for approximately \$1.98 billion in cash (the “LDH Acquisition”). We contributed approximately \$1.38 billion to ETP-Regency LLC to fund our 70% share of the purchase price. Subsequent to closing, ETP-Regency LLC was renamed Lone Star NGL LLC.

Completed construction of the 400 MMcf/d expansion of our Tiger pipeline ahead of schedule. The Tiger pipeline expansion was placed in service on August 1, 2011, bringing the total capacity of the Tiger pipeline to 2.4 Bcf/d.

Issued an aggregate of 31,811,893 Common Units for total net proceeds of \$1.47 billion primarily to fund acquisitions, internal growth projects and capital contributions to joint ventures and to manage our investment grade metrics.

Issued \$1.5 billion of senior notes in May 2011 to repay borrowings on our revolving credit facility.



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Amended our revolving credit facility to increase the capacity from \$2.0 billion to \$2.5 billion and extend the maturity date to 2016.

Announced our pending Citrus Acquisition, which is discussed in "Recent Developments and Current Growth Projects" below.

- Announced growth projects aggregating \$3.5 billion, including growth projects announced in 2012, which are expected to be placed in service through 2014.

To date in 2012, we have achieved the following:

- Issued \$2.0 billion of senior notes in January 2012, the proceeds from which we anticipate using to fund the cash portion of the Citrus Acquisition, which is discussed in "Recent Developments and Current Growth Projects" below, and for general partnership purposes.

Completed the repurchase of approximately \$750 million of our senior notes.

Completed the contribution of our retail propane businesses to AmeriGas as discussed below.

### Recent Developments and Current Growth Projects

#### Propane Operations

On January 12, 2012, we contributed our propane operations, consisting of HOLP and Titan (collectively, the "Propane Business"), to AmeriGas. We received approximately \$1.46 billion in cash and approximately 29.6 million AmeriGas common units in consideration for the contribution of the Propane Business, plus the assumption by AmeriGas of approximately \$71 million of existing HOLP debt. This transaction improved our liquidity and allows us to focus on our core businesses in the natural gas and NGL markets. As a result of this transaction, we have not included a discussion of the assets or operations of the Propane Business in Item 1.

#### Red River Gathering Pipeline

In October 2011, we entered into a long-term, fee-based agreement with XTO Energy, a subsidiary of ExxonMobil, to provide natural gas gathering, processing and transportation services from both the Woodford and Barnett Shale regions. We will construct a 117-mile, 24- and 30-inch natural gas gathering pipeline from the Woodford Shale to our existing gathering and processing infrastructure in the Barnett Shale. The pipeline will have an initial capacity of 450 MMcf/d, with anticipated capacity expansion exceeding 550 MMcf/d. The pipeline is expected to be in service by the fourth quarter of 2012. As part of the pipeline project, we will also construct a new 200 MMcf/d cryogenic processing plant at our existing Godley processing facility in Johnson County, Texas. The new processing plant will increase our processing capacity at Godley from 500 MMcf/d to 700 MMcf/d and is expected to be in service by the third quarter of 2013. The total cost to build the pipeline and processing plant is estimated to be approximately \$350 million to \$375 million.

#### Citrus Acquisition

In July 2011, we entered into an Amended and Restated Agreement and Plan of Merger with ETE (the "Citrus Merger Agreement") pursuant to which it is anticipated that Southern Union Company, a Delaware corporation ("SUG"), will cause the contribution to us of a 50% interest in Citrus Corp., which owns 100% of the Florida Gas Transmission ("FGT") pipeline system, in exchange for approximately \$1.895 billion in cash and \$105 million of our Common Units (the "Citrus Acquisition"), contemporaneous with the completion of the merger between SUG and ETE pursuant to the Second Amended and Restated Agreement and Plan of Merger between ETE and SUG (the "SUG Merger Agreement") as described in Note 3 to our consolidated financial statements included in this report. In order to increase the expected accretion to be derived from the Citrus Acquisition, ETE has agreed to relinquish its rights to approximately \$220 million of the incentive distributions from ETP that ETE would otherwise be entitled to receive over 16 consecutive quarters following the closing of the transaction. Citrus Corp. is currently jointly owned by SUG and El Paso Corporation. The FGT pipeline system has a capacity of 3.0 Bcf/d. FGT's primary customers are utilities with strong investment grade credit ratings; FGT's long-term contracts with these high credit quality customers are expected to increase our fee-based revenue stream.

In connection with the Citrus Merger Agreement, ETE has granted us a right of first offer with respect to any disposition by ETE or SUG of Southern Union Gas Services, a subsidiary of SUG that owns and operates a natural gas gathering and processing system serving the Permian Basin in West Texas and New Mexico.

#### Lone Star's West Texas Gateway Pipeline

In June 2011, Lone Star announced the construction of a NGL pipeline ("West Texas Gateway Pipeline") that extends from Winkler County in west Texas to our processing plant in Jackson County, Texas, which is currently under construction. Approximately

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60% of the expected pipeline capacity is currently committed under long-term fee-based contracts. Currently, this project is expected to be completed as an approximately 570-mile NGL pipeline with total estimated costs of \$917 million, which will be funded by contributions from us and Regency based on our respective ownership interests. In addition, Lone Star has secured capacity on our recently-announced NGL pipeline from Jackson County to Mont Belvieu, Texas.

### Lone Star's Mont Belvieu Fractionation Facility

In May 2011, we announced that Lone Star will construct a 100,000 Bbls/d NGL fractionation facility at Mont Belvieu, Texas. We will utilize a substantial amount of this fractionation capacity to handle NGL barrels we will deliver from the new processing facility we plan to build in Jackson County, Texas, a facility supported by multiple 10-year contracts with producers as part of our Eagle Ford Shale projects. Please read "Expansion of Eagle Ford Shale Projects" below. Additionally, Regency plans to provide NGL barrels to this facility for fractionation. As part of this project, Lone Star is developing additional storage facilities for NGLs and other liquids. The project will also include interconnectivity infrastructure to provide NGL suppliers with significant access to storage, other fractionators, pipelines and multiple markets along the Texas and Louisiana Gulf Coast. Total cost of this project is expected to be between \$375 million and \$400 million and is expected to be completed in the first quarter of 2013.

In February 2012, Lone Star announced the construction of a second 100,000 Bbls/d fractionation facility at Mont Belvieu, Texas. Supported by multiple long-term contracts, the second fractionator is necessary to handle the increasing NGL barrels delivered via the partnership's Woodford Shale, Eagle Ford Shale and Permian Basin infrastructure, including Lone Star's 570-mile West Texas Gateway NGL Pipeline. This second fractionation facility is expected to be completed in the first quarter of 2014 at an estimated cost of \$350 million.

### Expansion of Eagle Ford Shale Projects

In April 2011, we announced that we had entered into long-term fee-based agreements with multiple producers, including Rosetta Resources Operating LP, SM Energy Company, and a subsidiary of Anadarko Petroleum Corporation, to provide natural gas gathering, processing, and liquids services from the Eagle Ford Shale. To facilitate these agreements, which include volume commitments in excess of 540,000 MMBtu/d of natural gas, we will expand the previously announced REM pipeline in south Texas and will construct a new processing facility in Jackson County, Texas. The REM pipeline expansion, which will extend from our Chisholm Pipeline in DeWitt County east into Jackson County, Texas, will add approximately 70 miles of 42-inch pipe to the initial 160-mile, 30-inch pipeline that was announced in February 2011. We completed the initial phase of REM in October 2011 and completion of the REM expansion is scheduled for the fourth quarter of 2012. The first phase of the Jackson County gas processing plant is scheduled for completion in the first quarter of 2013.

In May 2011, we announced that we were considering alternatives to secure NGL pipeline capacity from Jackson County, Texas to Mont Belvieu. Subsequently, we decided to construct a 130-mile, 20-inch NGL pipeline from the new processing facility we plan to build in Jackson County to Mont Belvieu. This pipeline would provide capacity for NGL barrels from the Eagle Ford Shale and from Lone Star's West Texas Gateway Pipeline from west Texas. The capacity of the proposed 20-inch pipeline is expected to be approximately 340,000 Bbls/d and is expected to be completed by the third quarter of 2013.

In February 2012, we announced our entry into multiple long-term, fee-based agreements with producers to provide natural gas gathering, processing, and liquids services from the Eagle Ford Shale in south Texas. To facilitate the agreements, we will further expand the REM pipeline and construct a new processing facility at an expected cost of \$210 million. The pipeline expansion announced in February 2012 is expected to be completed in the fourth quarter of 2013, and the processing facility announced in February 2012 is expected to be completed in the fourth quarter of 2012. When fully constructed, the REM pipeline will consist of approximately 257 miles of large diameter pipe with a capacity of at least 1 Bcf/d.

### Segment Overview

Our segments and business are as described below. See Note 12 to our consolidated financial statements for additional financial information about our segments.

#### Intrastate Transportation and Storage Segment

Through our intrastate transportation and storage segment, we own and operate approximately 8,300 miles of natural gas transportation pipelines and three natural gas storage facilities located in the state of Texas.

Through ETC OLP, we own the largest intrastate pipeline system in the United States with interconnects to Texas markets and to major consumption areas throughout the United States. Our intrastate transportation and storage segment focuses on the transportation of natural gas to major markets from various prolific natural gas producing areas through connections with other pipeline systems as well as through our Oasis pipeline, our East Texas pipeline, our natural gas pipeline and storage assets that we refer to as ET Fuel System, and our HPL System, which are described below.

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Our intrastate transportation and storage segment's results are determined primarily by the amount of capacity our customers reserve as well as the actual volume of natural gas that flows through the transportation pipelines. Under transportation contracts, our customers are charged (i) a demand fee, which is a fixed fee for the reservation of an agreed amount of capacity on the transportation pipeline for a specified period of time and which obligates the customer to pay even if the customer does not transport natural gas on the respective pipeline, (ii) a transportation fee, which is based on the actual throughput of natural gas by the customer, (iii) fuel retention based on a percentage of gas transported on the pipeline, or (iv) a combination of the three, generally payable monthly.

We also generate revenues and margin from the sale of natural gas to electric utilities, independent power plants, local distribution companies, industrial end-users and other marketing companies on our HPL System. Generally, we purchase natural gas from either the market (including purchases from our midstream segment's marketing operations) or from producers at the wellhead. To the extent the natural gas comes from producers, it is primarily purchased at a discount to a specified market price and typically resold to customers based on an index price. In addition, our intrastate transportation and storage segment generates revenues from fees charged for storing customers' working natural gas in our storage facilities and from margin from managing natural gas for our own account. The major customers on our intrastate pipelines include Natural Gas Exchange, Inc., EDF Trading North America, Inc., XTO Energy, Inc. and ConocoPhillips.

### Interstate Transportation Segment

Through our interstate transportation segment, we own and operate approximately 2,880 miles of interstate natural gas pipeline and have a 50% interest in the joint venture that owns the 185-mile Fayetteville Express pipeline.

The results from our interstate transportation segment are primarily derived from the fees we earn from natural gas transportation services and, for the Transwestern pipeline, from operational gas sales. The major customers on our interstate pipelines include Chesapeake Energy Marketing, Inc., EnCana Marketing (USA), Inc. ("EnCana"), Shell Energy North America (US), L.P. and Pacific Summit Energy LLC.

### Midstream Segment

Through our midstream segment, we own and operate approximately 7,400 miles of in service natural gas gathering pipelines, two natural gas processing plants, 15 natural gas treating facilities and 11 natural gas conditioning facilities. Our midstream segment focuses on the gathering, compression, treating, blending, processing and marketing of natural gas, and our operations are currently concentrated in major producing basins and shales, including the Austin Chalk trend and Eagle Ford Shale in South and Southeast Texas, the Permian Basin in West Texas and New Mexico, the Barnett Shale in North Texas, the Bossier Sands in East Texas, the Uinta and Piceance Basins in Utah and Colorado, the Marcellus Shale in West Virginia, and the Haynesville Shale in East Texas and Louisiana. Many of our midstream assets are integrated with our intrastate transportation and storage assets.

Our midstream segment results are derived primarily from margins we earn for natural gas volumes that are gathered, transported, purchased and sold through our pipeline systems and the natural gas and NGL volumes processed at our processing and treating facilities. We also market natural gas on our pipeline systems in addition to other pipeline systems to realize incremental revenue on gas purchased, increase pipeline utilization and provide other services that are valued by our customers. The major customers on our midstream pipelines include Enterprise Products Partners L.P. ("Enterprise") and Chevron Phillips Chemical Company LP.

### NGL Transportation and Services Segment

Through our NGL transportation and services segment we own and operate an approximately 45-mile NGL pipeline and have a 50% interest in the Liberty pipeline, an approximately 85-mile NGL pipeline. We also have a 70% interest in the Lone Star joint venture that owns approximately 1,400 miles of NGL pipelines, three NGL processing plants, one fractionation facility and NGL storage facilities with aggregate working storage capacity of 47 million Bbls. NGL transportation revenue is principally generated from fees charged to customers under dedicated contracts or take-or-pay contracts. Under a dedicated contract, the customer agrees to deliver the total output from particular processing plants that are connected to the NGL pipeline. Take-or-pay contracts have minimum throughput commitments requiring the customer to pay regardless of whether a fixed volume is transported. Transportation fees are market-based, negotiated with customers and competitive with regional regulated pipelines.

NGL storage revenues are derived from base storage fees and throughput fees. Base storage fees are based on the volume of capacity reserved, regardless of the capacity actually used. Throughput fees are charged for providing ancillary services, including receipt and delivery, custody transfer, rail/truck loading and unloading fees. Storage contracts may be for dedicated storage or fungible storage. Dedicated storage enables a customer to reserve an entire storage cavern, which allows the customer to inject and withdraw proprietary and often unique products. Fungible storage allows a customer to store specified quantities of NGL

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products that are commingled in a storage cavern with other customers' products of the same type and grade. NGL storage contracts may be entered into on a firm or interruptible basis. Under a firm basis contract, the customer obtains the right to store products in the storage caverns throughout the term of the contract; whereas, under an interruptible basis contract, the customer receives only limited assurance regarding the availability of capacity in the storage caverns.

This segment also includes revenues earned from processing and fractionating refinery off-gas. Under these contracts we receive an Olefins-grade ("O-grade") stream from cryogenic processing plants located at refineries and fractionate the products into their pure components. We deliver purity products to customers through pipelines and across a truck rack located at the fractionation complex. In addition to revenues for fractionating the O-grade stream, we have percent-of-proceeds and income sharing contracts, which are subject to market pricing of olefins and NGLs. For percent-of-proceeds contracts, we retain a portion of the purity NGLs and olefins processed, or a portion of the proceeds from the sales of those commodities, as a fee. When NGLs and olefin prices increase, the value of the portion we retain as a fee increases. Conversely, when NGLs and olefin prices decrease, so does the value of the portion we retain as a fee. Under our income sharing contracts, we pay the producer the equivalent energy value for their liquids, similar to a traditional keep-whole processing agreement, and then share in the residual income created by the difference between NGLs and olefin prices as compared to natural gas prices. As NGLs and olefins prices increase in relation to natural gas prices, the value of the percent we retain as a fee increases. Conversely, when NGLs and olefins prices decrease as compared to natural gas prices, so does the value of the percent we retain as a fee. The major customers on our NGL pipelines include Targa Resources Partners LP, The Williams Companies, Inc. and Louis Dreyfus Highbridge Energy LLC.

### Retail Propane Segment

As of December 31, 2011, we owned one of the three largest retail propane marketers in the United States based on gallons sold and served more than one million customers through a nationwide retail distribution network consisting of approximately 440 customer service locations in approximately 40 states. The propane operations extended from coast to coast with concentrations in the western, upper midwestern, northeastern and southeastern regions of the United States.

As discussed above, in January 2012 we contributed our propane operations to AmeriGas. See further discussion of this transaction in "Recent Developments and Current Growth Projects" above.

### All Other

Segments below the quantitative thresholds are classified as "other." Management has included the wholesale propane and natural gas compression services operations in "other" for all periods presented in this report because such operations are not material.

The following assets are held in connection with our other natural gas operations:

We own 100% of the membership interests of Energy Transfer Group, L.L.C. ("ETG"), which owns all of the partnership interests of Energy Transfer Technologies, Ltd. ("ETT"). ETT provides compression services to customers engaged in the transportation of natural gas, including our other segments.

We also own all of the outstanding equity interests of a natural gas compression equipment business with operations in Arkansas, California, Colorado, Louisiana, New Mexico, Oklahoma, Pennsylvania and Texas.

### Asset Overview

#### Intrastate Transportation and Storage Segment

The following details our pipelines and storage facilities in the intrastate transportation and storage segment.

#### ET Fuel System

##### Capacity of 5.2 Bcf/d

• Approximately 2,950 miles of natural gas pipeline

• Two storage facilities with 12.4 Bcf of total working gas capacity

• Bi-directional capabilities

The ET Fuel System serves some of the most active drilling areas in the United States and is comprised of intrastate natural gas pipeline and related natural gas storage facilities. With approximately 560 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 near Midland, Texas, the Katy Hub near Houston, Texas and the Carthage Hub in East Texas, the three major natural gas trading centers in Texas. The major shippers on our pipelines include EOG Resources, Inc., Chesapeake Energy Marketing, Inc., XTO Energy, Inc. (“XTO”), Luminant Energy Company LLC, and EnCana.



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The ET Fuel System also includes our Bethel natural gas storage facility, with a working capacity of 6.4 Bcf, an average withdrawal capacity of 300 MMcf/d and an injection capacity of 75 MMcf/d, and our Bryson natural gas storage facility, with a working capacity of 6.0 Bcf, an average withdrawal capacity of 120 MMcf/d and an average injection capacity of 96 MMcf/d. All of our storage capacity on the ET Fuel System is contracted to third parties under fee-based arrangements that expire in 2012 and 2013.

In addition, the ET Fuel System is integrated with our Godley processing plant which gives us the ability to bypass the plant when processing margins are unfavorable by blending the untreated natural gas from the North Texas System with natural gas on the ET Fuel System while continuing to meet pipeline quality specifications.

### Oasis Pipeline

• Capacity of 1.2 Bcf/d

• Approximately 600 miles of natural gas pipeline

• Connects Waha to Katy market hubs

The Oasis pipeline is primarily a 36-inch 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 (i) providing access for natural gas on the Southeast Texas System to other third party supply and market points and interconnecting pipelines and (ii) allowing us to bypass our processing plants and treating facilities on the Southeast Texas System when processing margins are unfavorable by blending untreated natural gas from the Southeast Texas System with gas on the Oasis pipeline while continuing to meet pipeline quality specifications.

### HPL System

• Capacity of 5.5 Bcf/d

• Approximately 4,350 miles of natural gas pipeline

• Bammel storage facility with 62 Bcf of total working gas capacity

The HPL System is an extensive network of intrastate natural gas pipelines, an underground Bammel storage reservoir and related transportation assets. The system has access to multiple sources of historically significant natural gas supply reserves from South Texas, the Gulf Coast of Texas, East Texas and the western Gulf of Mexico, and is directly connected to major gas distribution, electric and industrial load centers in Houston, Corpus Christi, Texas City and other cities located along the Gulf Coast of Texas. The HPL System is well situated to gather and transport gas in many of the major gas producing areas in Texas including the strong presence in the key Houston Ship Channel and Katy Hub markets, allowing us to play an important role in the Texas natural gas markets. The HPL System also offers its shippers off-system opportunities due to its numerous interconnections with other pipeline systems, its direct access to multiple market hubs at Katy, the Houston Ship Channel and Agua Dulce, and our Bammel storage facility. The Bammel storage facility has a total working gas capacity of approximately 62 Bcf, a peak withdrawal rate of 1.3 Bcf/d and a peak injection rate of 0.6 Bcf/d. The Bammel storage facility is located near the Houston Ship Channel market area and the Katy Hub and is ideally suited to provide a physical backup for on-system and off-system customers. As of December 31, 2011, we had approximately 13.7 Bcf committed under fee-based arrangements with third parties and approximately 48.6 Bcf stored in the facility for our own account.

### East Texas Pipeline

• Capacity of 2.4 Bcf/d

• Approximately 370 miles of natural gas pipeline

The East Texas pipeline connects three treating facilities, one of which we own, with our Southeast Texas System. The East Texas pipeline was the first phase of a multi-phased project that increased service to producers in East and North Central Texas and provided access to the Katy Hub. The East Texas pipeline expansions include the 36-inch

East Texas extension to connect our Reed compressor station in Freestone County to our Grimes County compressor station, the 36-inch Katy expansion connecting Grimes to the Katy Hub, and the 42-inch Southeast Bossier pipeline connecting our Cleburne to Carthage pipeline to the HPL System. Key shippers on the East Texas pipeline include XTO and EnCana with an average of approximately 540,000 MMBtu/d and 200,000 MMBtu/d, respectively.

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### Interstate Transportation Pipelines

The following details our pipelines in the interstate transportation segment.

#### Transwestern Pipeline

Capacity of 2.1 Bcf/d

Approximately 2,690 miles of interstate natural gas pipeline

Bi-directional capabilities

The Transwestern pipeline is an open-access interstate natural gas pipeline extending from the gas producing regions of West Texas, eastern and northwestern New Mexico, and southern Colorado primarily to pipeline interconnects off the east end of its system and to pipeline interconnects at the California border. The Transwestern pipeline has access to three significant gas basins: the Permian Basin in West Texas and eastern New Mexico; the San Juan Basin in northwestern New Mexico and southern Colorado; and the Anadarko Basin in the Texas and Oklahoma panhandle. Natural gas sources from the San Juan Basin and surrounding producing areas can be delivered eastward to Texas intrastate and mid-continent connecting pipelines and natural gas market hubs as well as westward to markets in Arizona, Nevada and California. Transwestern's Phoenix lateral pipeline, with a throughput capacity of 500 MMcf/d, connects the Phoenix area to the Transwestern mainline.

Transwestern's customers include local distribution companies, producers, marketers, electric power generators and industrial end-users. Transwestern transports natural gas in interstate commerce.

#### Tiger Pipeline

Capacity of 2.4 Bcf/d

Approximately 195 miles of interstate natural gas pipeline

Bi-directional capabilities

The Tiger pipeline is an approximately 195-mile interstate natural gas pipeline that connects to our dual 42-inch pipeline system near Carthage, Texas, extends through the heart of the Haynesville Shale and ends near Delhi, Louisiana, with interconnects to at least seven interstate pipelines at various points in Louisiana. The pipeline has a capacity of 2.4 Bcf/d, all of which is sold under long-term contracts ranging from 10 to 15 years.

#### Fayetteville Express Pipeline

Capacity of 2.0 Bcf/d

Approximately 185 miles of interstate natural gas pipeline

50/50 joint venture with Kinder Morgan Energy Partners, L.P. ("KMP")

The Fayetteville Express pipeline is an approximately 185-mile interstate natural gas pipeline that originates near Conway County, Arkansas, continues eastward through White County, Arkansas and terminates at an interconnect with Trunkline Gas Company in Panola County, Mississippi. The pipeline has long-term contracts for 1.85 Bcf/d ranging from 10 to 12 years. The Fayetteville Express pipeline is a 50/50 joint venture with KMP.

#### Midstream

The following details our assets in the midstream segment.

#### Southeast Texas System

Approximately 5,540 miles of natural gas pipeline

One natural gas processing plant (the La Grange plant) with aggregate capacity of 210 MMcf/d

12 natural gas treating facilities with aggregate capacity of 1.6 Bcf/d

Four natural gas conditioning facilities with aggregate capacity of 650 MMcf/d

The Southeast Texas System is an integrated system that gathers, compresses, treats, processes and transports natural gas from the Austin Chalk trend. The La Grange processing plant also processes rich gas from the Eagle Ford Shale. The Southeast Texas System is a large natural gas gathering system covering thirteen counties between Austin and Houston. This system is connected to the Katy Hub through the East Texas pipeline and is connected to the Oasis pipeline, as well as two power plants. This allows us to bypass our processing plants and treating facilities when

processing margins are unfavorable by blending untreated natural gas from the Southeast Texas System with natural gas on the Oasis pipeline while continuing to meet pipeline quality specifications.

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The La Grange processing plant is a cryogenic natural gas processing plant that processes the rich natural gas that flows through our system to produce residue gas and NGLs.

Our treating facilities remove carbon dioxide and hydrogen sulfide from natural gas gathered into our system before the natural gas is introduced to transportation pipelines to ensure that the gas meets pipeline quality specifications. In addition, our conditioning facilities remove heavy hydrocarbons from the gas gathered into our systems so the gas can be redelivered and meet downstream pipeline hydrocarbon dew point specifications.

### North Texas System

• Approximately 160 miles of natural gas pipeline

• One natural gas processing plant (the Godley plant) with aggregate capacity of 480 MMcf/d

• One natural gas conditioning facility with capacity of 100 MMcf/d

The North Texas System is an integrated system located in four counties in North Texas that gathers, compresses, treats, processes and transports natural gas from the Barnett Shale trend. The system includes our Godley processing plant, which processes rich natural gas produced from the Barnett Shale and is integrated with the North Texas System and the ET Fuel System. The facility consists of a cryogenic processing plant and a conditioning facility.

### Canyon Gathering System

• Approximately 1,390 miles of natural gas pipeline

• Five natural gas conditioning facilities with aggregate capacity of 96 MMcf/d

The Canyon Gathering System consists of gathering pipeline ranging in diameters from two inches to 24 inches in the Piceance and Uinta Basins of Colorado and Utah and conditioning plants.

### Northern Louisiana

• Approximately 240 miles of natural gas pipeline

• Three natural gas treating facilities with aggregate capacity of 385 MMcf/d

Our Northern Louisiana assets comprise several gathering systems in the Haynesville Shale with access to multiple markets through interconnects with several pipelines, including our Tiger pipeline. Our Northern Louisiana assets include the Bistineau, Creedence, and Tristate Systems.

### Other Midstream Assets

The midstream segment also includes our interests in various midstream assets located in Texas, New Mexico and Louisiana, with gathering pipelines aggregating a combined capacity of approximately 115 MMcf/d, as well as one conditioning facility. We also own gathering pipelines serving the Marcellus Shale in West Virginia with aggregate capacity of approximately 250 MMcf/d.

### Marketing Operations

We conduct marketing operations in which we market the natural gas that flows through our gathering and intrastate transportation assets, referred to as on-system gas. We also attract other customers by marketing volumes of natural gas that do not move through our assets, referred to as off-system gas. For both on-system and off-system gas, we purchase natural gas from natural gas producers and other suppliers 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 of natural gas, less the costs of transportation.

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

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### NGL Transportation and Services

The following details our assets in the NGL transportation and services segment. All assets described below are owned by Lone Star, in which we have a 70% interest.

#### West Texas System

• Capacity of 137,000 Bbls/d

• Approximately 1,170 miles of NGL transmission pipelines

The West Texas System is an intrastate NGL pipeline consisting of 3-inch to 16-inch long-haul, mixed NGLs transportation pipeline that delivers 137,000 Bbls/d of capacity from the Regency Waha Processing Plant in the Permian Basin and our Godley Processing Plant in the Barnett Shale to the Mont Belvieu NGL storage facility.  
Mont Belvieu Storage Facility

• Working storage capacity of approximately 43 million Bbls

• Approximately 140 miles of NGL transmission pipelines

The Mont Belvieu storage facility is an integrated liquids storage facility with over 43 million Bbls of salt dome capacity and 23 million Bbls of brine pond capacity, providing 100% fee-based cash flows. The Mont Belvieu storage facility has access to multiple NGL and refined product pipelines, the Houston Ship Channel trading hub, and numerous chemical plants, refineries and fractionators.

#### Hattiesburg Storage Facility

• Working storage capacity of four million Bbls

The Hattiesburg storage facility is an integrated liquids storage facility with approximately four million Bbls of salt dome capacity, providing 100% fee-based cash flows.

#### Sea Robin Processing Plant

• One cryogenic processing plant (the Chalmette Plant) with 850 MMcf/d residue capacity and 26,000 Bbls/d NGL capacity

• 20% non-operating interest held by Lone Star

Sea Robin is a cryogenic rich gas processing plant located on the Sea Robin Pipeline in southern Louisiana. The plant, which is connected to nine interstate and four intrastate residue pipelines as well as various deep-water production fields, has a residue capacity of 850 MMcf/d and an NGL capacity of 26,000 Bbls/d.

#### Refinery Services

• One cryogenic processing plant (the Chalmette Plant) with 54 MMcf/d capacity

• One cryogenic processing plant (the Sorrento Plant) with 28 MMcf/d capacity

• One NGL fractionator with 25,000 Bbls/d capacity

• Approximately 100 miles of NGL pipelines

Refinery Services consists of a refinery off-gas processing and O-grade NGL fractionation complex located along the Mississippi River refinery corridor in southern Louisiana that cryogenically processes refinery off-gas and fractionates the O-grade NGL stream into its higher value components. The O-grade fractionator located in Geismar, Louisiana is connected by approximately 100 miles of pipeline to the Sorrento and Chalmette cryogenic processing plants.

#### Business Strategy

We have designed our business strategy with the goal of increasing 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 strategic 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 natural gas and NGL operations, we will be best positioned to

achieve our objectives. We balance our desire for growth with our goal of preserving a strong balance sheet, strong liquidity and investment grade credit metrics.

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We expect that acquisitions in natural gas and NGL operations will be the primary focus of our acquisition strategy going forward. We also anticipate that our natural gas operations will provide internal growth projects of greater scale as demonstrated by our significant number of completed natural gas pipeline projects.

Following is a summary of the business strategies of our core natural gas and NGL related businesses:

Enhance profitability of existing assets. We intend to increase the profitability of our existing asset base by adding new volumes under long-term producer commitments, 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 and transportation services.

Increase cash flow from fee-based businesses. We intend to increase the percentage of our business conducted with third parties under fee-based arrangements in order to provide for stable, consistent cash flows over long contract periods while reducing exposure to changes in commodity prices.

Growth through acquisitions. We intend to continue to make strategic acquisitions in our areas of operation that offer the opportunity for operational efficiencies and the potential for increased utilization and expansion of our existing and acquired assets.

### Industry Overview

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

Natural gas has widely varying quality and composition, depending on the field, the formation or the reservoir from which it is produced. The principal constituents of natural gas are methane and ethane, though most natural gas also contains varying amounts of heavier components, such as propane, butane and natural gasoline that may be removed by a number of processing methods.

Most raw materials produced at the wellhead are not suitable for long-haul pipeline transportation or commercial use and must be compressed, transported via pipeline to a central processing facility, and then processed to remove the heavier hydrocarbon components and other contaminants that would interfere with pipeline transportation or the end use of the gas.

Natural gas and crude oil produced at the wellhead contain varying amounts of mixed NGLs. After extraction by a processing plant the mixed NGLs are transported to a facility for fractionation into NGL products such as ethane, propane, butane, and natural gasoline. The NGL products are then delivered to end-users through pipelines, trucks, rail car and barges. End-users of NGL products include petrochemical, refining companies and end-use propane customers.

Demand for natural gas. Natural gas continues to be a critical component of energy consumption in the United States. According to data released in December 2011 by the Energy Information Administration, total domestic consumption of natural gas is expected to rise to 26.5 Tcf in 2035 compared to 2010 consumption of 24.1 Tcf. The industrial and electricity generation sectors currently account for more than half of natural gas usage in the United States.

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

Natural gas compression. Gathering systems are operated at design pressures that will maximize the total throughput from all connected wells. Specifically, lower pressure gathering systems allow wells, which produce at progressively lower field pressures as they age, to remain connected to gathering systems and to continue to produce for longer periods of time. As the pressure of a well declines, it becomes increasingly 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 might not be produced.

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

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

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

**NGL transportation.** NGL transportation pipelines transport mixed NGLs and other hydrocarbons from natural gas processing facilities to fractionation plants and storage facilities.

**NGL storage.** NGL storage facilities are used for the storage of mixed NGLs, NGL products and petrochemical products owned by third-parties in storage tanks and underground wells, which allow for the injection and withdrawal of such products at various times of the year to meet demand cycles.

**NGL Fractionation and Processing.** NGL fractionators separate mixed NGL streams into purity products, such as ethane, propane, normal butane, isobutane and natural gasoline.

### **Competition**

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

We face competition with respect to retaining and obtaining significant natural gas supplies under terms favorable to us for the gathering, treating and marketing portions of our business. Our competitors include major integrated oil companies, interstate and

intrastate pipelines and companies that gather, compress, treat, process, transport and market natural gas. Many of our competitors, such as major oil and gas and pipeline companies, have capital resources and control supplies of natural gas substantially greater than ours.

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

In markets served by our NGL pipelines, we face competition with other pipeline companies and barge, rail and truck fleet operations. We face competition with other storage facilities based on fees charged and the ability to receive and distribute the customer's products.

### **Credit Risk and Customers**

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

Our counterparties consist primarily of petrochemical companies and other industrials, small to major oil and gas producers, midstream, and power generation companies. This concentration of counterparties may impact our overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions. Currently, management does not anticipate a material adverse effect on financial position or results of operations as a result of counterparty performance.

Our natural gas transportation and midstream revenues are derived significantly from companies that engage in natural gas exploration and production activities. Prices for natural gas have been negatively impacted in recent years by economic conditions and the discovery and development of new shale formations. As a result, many of our customers have been negatively impacted. We are diligent in attempting to mitigate credit risk relating to our customers.

During the year ended December 31, 2011, none of our customers individually accounted for more than 10% of our consolidated revenues.



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### Regulation

Regulation of Interstate Natural Gas Pipelines. The FERC has broad regulatory authority over the business and operations of interstate natural gas pipelines. Under the Natural Gas Act (“NGA”), the FERC generally regulates the transportation of natural gas in interstate commerce. For FERC regulatory purposes, “transportation” includes natural gas pipeline transmission (forwardhauls and backhauls), storage and other services. The Transwestern and Tiger pipelines transport natural gas in interstate commerce and thus both pipelines qualify as a “natural gas company” under the NGA subject to the FERC’s regulatory jurisdiction. We also hold a joint venture interest in the Fayetteville Express pipeline, an NGA-jurisdictional interstate transportation system subject to the FERC’s broad regulatory oversight. The FERC’s NGA authority includes the power to regulate:

- the certification and construction of new facilities;
- the review and approval of transportation rates;
- the types of services that our regulated assets are permitted to perform;
- the terms and conditions associated with these services;
- the extension or abandonment of services and facilities;
- the maintenance of accounts and records;
- the acquisition and disposition of facilities; and
- the initiation and discontinuation of services.

Under the NGA, interstate natural gas companies must charge rates that are just and reasonable. In addition, the NGA prohibits natural gas companies from unduly preferring or unreasonably discriminating against any person with respect to pipeline rates or terms and conditions of service.

Under the terms of a prior settlement, Transwestern was required to file a new NGA Section 4 general rate case no later than October 1, 2011. However, on September 2, 2011, the FERC granted Transwestern's request for an extension of the filing date until December 1, 2011. On September 21, 2011, in lieu of filing a new rate case, Transwestern filed a proposed settlement with the FERC, which was approved by the FERC on October 31, 2011. In general, the settlement provides for the continued use of Transwestern's currently effective transportation and fuel tariff rates, with the exception of certain San Juan Lateral fuel rates which will be reduced over a three year period beginning in April 2012. The settlement also resolves certain non-rate matters, and approves Transwestern's use of certain previously approved accounting methodologies. Under the settlement, Transwestern is required to file a new NGA Section 4 rate case on or before October 1, 2014.

In December 2009, the FERC issued an order granting Fayetteville Express Pipeline LLC (“FEP”) authorization to construct and operate the Fayetteville Express pipeline, subject to certain conditions, and FEP accepted the FERC’s certificate. Interim service began on the Fayetteville Express pipeline in the fourth quarter of 2010 and commenced service to all of its firm shippers on December 1, 2010, with the primary term of each firm shipper’s contract commencing by January 1, 2011. The rates charged for services on the Fayetteville Express pipeline are largely governed by long-term negotiated rate agreements. In the certificate order, the FERC also approved cost-based recourse rates available to prospective shippers as an alternative to negotiated rates.

In April 2010, the application for authority to construct the Tiger pipeline was approved by the FERC and field construction began on the pipeline in June 2010. The Tiger pipeline was placed in service on December 1, 2010. The rates charged for services on the Tiger pipeline are largely governed by long-term negotiated rate agreements. In June 2010, we filed an application for authority to construct and operate a 0.4 Bcf/d expansion of the Tiger pipeline with the FERC and in February 2011 we accepted the FERC’s certificate order authorizing the construction and operation of this expansion and the rate-related arrangements for the services to be provided on this expansion. The expansion was placed in service on August 1, 2011.

The maximum rates to be charged by NGA-jurisdictional natural gas companies and their terms and conditions for service are generally required to be on file with the FERC in FERC-approved tariffs. Most natural gas companies are authorized to offer discounts from their FERC-approved maximum just and reasonable rates when competition warrants such discounts. Natural gas companies are also generally permitted to offer negotiated rates different from rates established in their tariff if, among other requirements, such companies’ tariffs offer a cost-based recourse rate

available to a prospective shipper as an alternative to the negotiated rate. Natural gas companies must make offers of rate discounts and negotiated rates on a basis that is not unduly discriminatory. Existing tariff rates may be challenged by complaint, and if found unjust and unreasonable, may be altered on a prospective basis by the FERC. We cannot guarantee that the FERC will continue to pursue its approach of pro-competitive policies as it considers matters such as pipeline rates and rules and policies that may affect rights of access to natural gas transportation capacity, transportation and storage facilities.

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Pursuant to the FERC's rules promulgated under the Energy Policy Act of 2005, it is unlawful for any entity, directly or indirectly, in connection with the purchase or sale of electric energy or natural gas or the purchase or sale of transmission or transportation services subject to FERC jurisdiction: (1) to defraud using any device, scheme or artifice; (2) to make any untrue statement of material fact or omit a material fact; or (3) to engage in any act, practice or course of business that operates or would operate as a fraud or deceit. The Commodity Futures Trading Commission ("CFTC") also holds authority to monitor certain segments of the physical and futures energy commodities market pursuant to the Commodity Exchange Act ("CEA"). With regard to our physical purchases and sales of natural gas, NGLs or other energy commodities; our gathering or transportation of these energy commodities; and any related hedging activities that we undertake, we are required to observe these anti-market manipulation laws and related regulations enforced by the FERC and/or the CFTC. These agencies hold substantial enforcement authority, including the ability to assess civil penalties of up to \$1 million per day per violation, to order disgorgement of profits and to recommend criminal penalties. Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third party damage claims by, among others, sellers, royalty owners and taxing authorities.

Failure to comply with the NGA, the Energy Policy Act of 2005 and the other federal laws and regulations governing our operations and business activities can result in the imposition of administrative, civil and criminal remedies.

**Regulation of Intrastate Natural Gas and NGL Pipelines.** Intrastate transportation of natural gas and NGLs is largely regulated by the state in which such transportation takes place. To the extent that our intrastate natural gas transportation systems transport natural gas in interstate commerce, the rates, terms and conditions of such services are subject to FERC jurisdiction under Section 311 of the Natural Gas Policy Act ("NGPA"). The NGPA 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. The rates, terms and conditions of some transportation and storage services provided on the Oasis pipeline, HPL System, East Texas pipeline and ET Fuel System are subject to FERC regulation pursuant to Section 311 of the NGPA. Under Section 311, rates charged for intrastate transportation must be fair and equitable, and amounts collected in excess of fair and equitable rates are subject to refund with interest. The terms and conditions of service set forth in the intrastate facility's statement of operating conditions are also subject to the FERC review and approval. Should the FERC determine not to authorize rates equal to or greater than our currently approved Section 311 rates, our business may be adversely affected. Failure to observe the service limitations applicable to transportation and storage services under Section 311, failure to comply with the rates approved by the FERC for Section 311 service, and failure to comply with the terms and conditions of service established in the pipeline's FERC-approved statement of operating conditions could result in an alteration of jurisdictional status, and/or the imposition of administrative, civil and criminal remedies.

The FERC has adopted market-monitoring and annual reporting regulations, which regulations are applicable to many intrastate pipelines as well as other entities that are otherwise not subject to the FERC's NGA jurisdiction such as natural gas marketers. These regulations are intended to increase the transparency of wholesale energy markets, to protect the integrity of such markets, and to improve the FERC's ability to assess market forces and detect market manipulation. The FERC has also issued regulations requiring interstate pipelines and certain major non-interstate pipelines to post, on a daily basis, capacity, scheduled flow information and actual flow information. As these posting requirements for major non-interstate pipelines have been vacated on appeal by the U.S. 5<sup>th</sup> Circuit Court of Appeals, it is not known with certainty whether and to what extent the FERC will continue to attempt to impose such posting requirements. Should the FERC succeed in reimposing these or similar regulations we could be subject to further costs and administrative burdens, none of which are expected to have a material impact on our operations.

Our intrastate natural gas operations are also subject to regulation by various agencies in Texas, principally the Texas Railroad Commission ("TRRC"). Our intrastate pipeline and storage operations in Texas are also 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 rates we charge for transportation services are deemed just and reasonable under Texas law unless challenged in a customer or TRRC 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.

Regulation of Sales of Natural Gas and NGLs. The price at which we buy and sell natural gas currently is not subject to federal regulation and, for the most part, is not subject to state regulation. The price at which we sell NGLs is not subject to federal or state regulation.

To the extent that we enter into transportation contracts with natural gas pipelines that are subject to FERC regulation, we are subject to FERC requirements related to use of such capacity. Any failure on our part to comply with the FERC's regulations and policies, or with an interstate pipeline's tariff, could result in the imposition of civil and criminal penalties.

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. The FERC is continually proposing

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and implementing new rules and regulations affecting those segments of the natural gas industry. 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 the FERC's regulatory changes may adversely affect the availability and reliability of interruptible transportation service on interstate pipelines. We do not believe that we will be affected by any such FERC action in a manner that is materially different from other natural gas marketers with whom we compete.

**Regulation of Gathering Pipelines.** Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of the FERC under the NGA. We own a number of natural gas pipelines in Texas, Louisiana, Colorado, West Virginia and Utah that we believe meet the traditional tests the FERC uses to establish a pipeline's status as a gatherer not subject to FERC jurisdiction. However, the distinction between the FERC-regulated transmission services and federally unregulated gathering services has been the subject of substantial litigation and varying interpretations, so the classification and regulation of our gathering facilities could be subject to change based on future determinations by the FERC and the courts. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements and complaint-based rate regulation. In Texas, our gathering facilities are subject to regulation by the TRRC under the Texas Utilities Code in the same manner as described above for our intrastate pipeline facilities. Louisiana's Pipeline Operations Section of the Department of Natural Resources' Office of Conservation is generally responsible for regulating intrastate pipelines and gathering facilities in Louisiana and has authority to review and authorize natural gas transportation transactions and the construction, acquisition, abandonment and interconnection of physical facilities.

Historically, apart from pipeline safety, Louisiana has not acted to exercise this jurisdiction respecting gathering facilities. In Louisiana, our Chalkley System is regulated as an intrastate transporter, and the Louisiana Office of Conservation has determined that our Whiskey Bay System is a gathering system.

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

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

**Regulation of Pipeline Safety.** Our pipeline operations are subject to regulation by the U.S. Department of Transportation ("DOT"), under the PHMSA, pursuant to which the PHMSA has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. In addition, the states in which we conduct operations administer federal pipeline safety standards under the Natural Gas Pipeline Safety Act of 1968, as amended (the "NGPSA"), which requires compliance with safety standards during construction and operation of certain the pipelines and subjects the pipelines to regular inspections. Failure to comply with the



safety laws and regulations may result in the imposition of administrative, civil and criminal remedies. The “rural gathering exemption” under the NGPSA presently exempts substantial portions of our gathering facilities from jurisdiction under the NGPSA, but does not apply to our intrastate natural gas pipelines. 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. Changes to federal pipeline safety laws and regulations are being considered by Congress and the DOT including changes to the “rural gathering exemption,” which may be restricted in the future. Other safety regulations may be made more stringent and penalties could be increased. Such legislative and regulatory changes could have a material effect on our operations and costs of transportation service.

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In addition to existing pipeline safety regulations, on January 3, 2012, President Obama signed into law the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, that increases pipeline safety regulation. Among other things, the legislation doubles the maximum administrative fines for safety violations from \$100,000 to \$200,000 for a single violation and from \$1 million to \$2 million for a related series of violations, and provides that these maximum penalty caps do not apply to civil enforcement actions; permits the DOT Secretary to mandate automatic or remote controlled shut off valves on new or entirely replaced pipelines; requires the DOT Secretary to evaluate whether integrity management system requirements should be expanded beyond high-consequence areas (“HCAs”), within 18 months of enactment; and provides for regulation of carbon dioxide transported by pipeline in a gaseous state and requires the DOT Secretary to prescribe minimum safety regulations for such transportation.

### Environmental Matters

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

- restricting how 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 did not comply with permit terms.

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

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

The Comprehensive Environmental Response, Compensation and Liability Act, as amended, also known as “CERCLA” or “Superfund,” and comparable state laws, impose liability without regard to fault or the legality of the original conduct on certain classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. One class of “responsible persons” is the current owners or operators of contaminated property, even if the contamination arose as a result of historical operations conducted by previous, unaffiliated occupants of the property. Under CERCLA, “responsible persons” may be subject to joint and several, strict liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies. It also is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances into the environment. Although “petroleum” is excluded from the definition of hazardous substance under CERCLA, we generate materials in the course of our operations that may be regulated as hazardous substances. We also may incur

liability under the Resource Conservation and Recovery Act, also known as “RCRA,” which imposes requirements related to the management and disposal of solid and hazardous wastes. While there exists an exclusion from the definition of hazardous wastes for “drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy,” in the course of our operations, we may generate certain types of non-excluded petroleum product wastes as well as ordinary industrial wastes such as paint wastes, waste solvents, and waste compressor oils that may be regulated as hazardous or solid wastes.

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We currently own or lease, and have in the past owned or leased, numerous properties that for many years have been used for the measurement, gathering, field compression and processing of natural gas and NGLs. Although we used operating and disposal practices that were standard in the industry at the time, petroleum hydrocarbons or wastes may have been disposed of or released on or under the properties owned or leased by us, or on or under other locations where such wastes were taken for disposal. In addition, some of these properties have been operated by third parties whose treatment and disposal or release of petroleum hydrocarbons and wastes was not under our control. These properties and the materials disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove or remediate previously disposed wastes or property contamination, or to perform remedial activities to prevent future contamination. A predecessor company acquired by us in July 2001 had previously received and responded to a request for information from the United States Environmental Protection Agency (the “EPA”) regarding its potential contribution to widespread groundwater contamination in San Bernardino, California, known as the Newmark Groundwater Contamination Superfund site. We have not received any follow-up correspondence from the EPA on the matter since our acquisition of the predecessor company in 2001. In addition, through our acquisitions of ongoing businesses, we are currently involved in several remediation projects that have cleanup costs and related liabilities. As of December 31, 2011 and 2010, accruals of \$13.7 million and \$13.8 million, respectively, were recorded in our consolidated balance sheets as accrued and other current liabilities and other non-current liabilities to cover estimated material environmental liabilities including certain matters assumed in connection with our acquisition of the HPL System, the Transwestern acquisition, potential environmental liabilities for three sites that were formerly owned by Titan or its predecessors and the predecessor owner’s share of certain environmental liabilities of ETC OLP.

Transwestern conducts soil and groundwater remediation at a number of its facilities. Some of the cleanup activities include remediation of several compressor sites on the Transwestern system for contamination by polychlorinated biphenyls (“PCBs”), and the costs of this work are not eligible for recovery in rates. The total accrued future estimated cost of remediation activities expected to continue through 2025 is \$5.7 million, which is included in the total environmental accruals mentioned above. Transwestern received FERC approval for rate recovery of projected soil and groundwater remediation costs not related to PCBs effective April 1, 2007.

Transwestern, as part of ongoing arrangements with customers, continues to incur costs associated with containing and removing potential PCB contamination. Future costs cannot be reasonably estimated because remediation activities are undertaken as potential claims are made by customers and former customers. However, such future costs are not expected to have a material impact on our financial position, results of operations or cash flows.

The Federal Water Pollution Control Act of 1972, as amended, also known as the Clean Water Act, and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into state and federal waters. The discharge of pollutants into regulated waters is prohibited, except in accord with the terms of a permit issued by EPA or the state. Any unpermitted release of pollutants, including NGLs or condensates, from our systems or facilities into regulated waters could result in fines or penalties, as well as significant remedial obligations. We believe that we are in compliance with the Clean Water Act. The regulations for the EPA’s Spill Prevention, Control and Countermeasures (“SPCC”) program were recently modified. We are currently reviewing the impact to our operations and expect to expend resources on tank integrity testing and any associated corrective actions as well as potential upgrades to containment structures. Costs associated with tank integrity testing and resulting corrective actions cannot be reasonably estimated at this time, but we believe such costs will not have a material adverse effect on our financial position, results of operations or cash flows.

The Federal Clean Air Act, as amended, and comparable state laws restrict the emission of air pollutants from many sources, including processing plants and compressor stations. These laws and any implementing regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions, impose stringent air permit requirements or utilize specific equipment or technologies to control emissions. Failure to comply with these laws and regulations could expose us to civil and criminal enforcement actions. We have established agency-approved baseline monitoring of NOx emissions from our Katy Compressor Station in Harris County, Texas, which is in a non-attainment area for ozone. The NOx baseline has been established and we have a sufficient amount of NOx emission allowances that would allow the facility to continue at

its current level of operation in the non-attainment area. On March 30, 2010, the Texas Commission on Environmental Quality (“TCEQ”) adopted two revisions to the state implementation plan responding to the EPA’s re-designation of the Houston area to a severe ozone non-attainment area. These revisions will require reductions in current emissions. By March 2013, TCEQ is required to develop a plan to address the recent change in the ozone standard from 0.08 parts per million (“ppm”) to 0.075 ppm. We expect these efforts will result in the adoption of new regulations that may require additional NOx emissions reductions at large emission sources in the Houston-Galveston ozone non-attainment area.

In December 2009, the EPA determined that emissions of carbon dioxide, methane and other “greenhouse gases” present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth’s atmosphere and other climatic changes. Based on these findings, the EPA has begun adopting and implementing regulations to restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. The

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EPA recently adopted two sets of rules regulating greenhouse gas emissions under the Clean Air Act, one of which requires a reduction in emissions of greenhouse gases from motor vehicles and the other of which regulates emissions of greenhouse gases from certain large stationary sources, effective January 2, 2011. The EPA's rules relating to emissions of greenhouse gases from large stationary sources of emissions are currently subject to a number of legal challenges, but the federal courts have thus far declined to issue any injunctions to prevent EPA from implementing, or requiring state environmental agencies to implement, the rules.

In addition, the United States Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and almost one-half of the states have already taken legal measures to reduce emissions of greenhouse gases primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall greenhouse gas emission reduction goal.

The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, natural gas or NGLs. Consequently, legislation and regulatory programs to reduce emissions of greenhouse gases could have an adverse effect on our business, financial condition and results of operations.

In addition, on October 30, 2009, the EPA published a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas sources in the United States on an annual basis, beginning in 2011 for emissions occurring after January 1, 2010. On November 8, 2010, the EPA adopted an expansion of its greenhouse gas reporting rule to include onshore oil and natural gas production, processing, transmission, storage, and distribution facilities. Under the rule reporting of greenhouse gas emissions from such facilities, including many of our facilities, is now required on an annual basis, with reporting beginning in 2012 for emissions occurring in 2011.

Some have suggested that one consequence of climate change could be increased severity of extreme weather, such as increased hurricanes and floods. If such effects were to occur, our operations could be adversely affected in various ways, including damages to our facilities from powerful winds or rising waters, or increased costs for insurance. Another possible consequence of climate change is increased volatility in seasonal temperatures. The market for our natural gas is generally improved by periods of colder weather and impaired by periods of warmer weather, so any changes in climate could affect the market for the fuels that we produce. Despite the use of the term "global warming" as a shorthand for climate change, some studies indicate that climate change could cause some areas to experience substantially colder temperatures than their historical averages. As a result, it is difficult to predict how the market for our fuels would be affected by increased temperature volatility, although if there is an overall trend of warmer temperatures, it would be expected to have an adverse effect on our business.

Our pipeline operations are subject to regulation by the DOT under the Pipeline Hazardous Materials Safety Administration ("PHMSA"), pursuant to which the PHMSA has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. Moreover, the PHMSA, through the Office of Pipeline Safety, has promulgated a rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the rule refers to as "high consequence areas." Activities under these integrity management programs involve the performance of internal pipeline inspections, pressure testing or other effective means to assess the integrity of these regulated pipeline segments, and the regulations require prompt action to address integrity issues raised by the assessment and analysis. Based on the results of our current pipeline integrity testing programs, we estimate that compliance with these federal regulations and analogous state pipeline integrity requirements will result in capital costs of \$3.4 million and operating and maintenance costs of \$17.9 million over the course of the next year. Integrity testing and assessment of all of these assets will continue, and the potential exists that results of such testing and assessment could cause us to incur even greater capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines.

We are subject to the requirements of the federal Occupational Safety and Health Act, also known as OSHA, and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA's hazardous communication standard requires that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in compliance with the OSHA requirements, including general industry standards, record keeping requirements, and monitoring of occupational exposure to regulated substances. National Fire Protection Association Pamphlets No. 54 and No. 58, which establish rules and procedures governing the safe handling of propane, or comparable regulations, have been adopted as the industry standard in all of the states in which we operate.

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In some states, these laws are administered by state agencies, and in others, they are administered on a municipal level. With respect to the transportation of propane by truck, we are subject to regulations governing the transportation of hazardous materials under the Federal Motor Carrier Safety Act, administered by the DOT. We conduct ongoing training programs to help ensure that our operations are in compliance with applicable regulations. We believe that the procedures currently in effect at all of our facilities for the handling, storage and distribution of propane are consistent with industry standards and are in substantial compliance with applicable laws and regulations.

**Employees**

As of January 31, 2012, we employed 1,946 persons, none of which are represented by labor unions. We believe that our relations with our employees are satisfactory. Our retail propane operations were contributed to AmeriGas on January 12, 2012; therefore, our employee headcount as of January 31, 2012 excluded employees of the retail propane operations.

**SEC Reporting**

We file or furnish annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and any related amendments and supplements thereto with the Securities and Exchange Commission ("SEC"). 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 or furnish with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. You may obtain information regarding the Public Reference Room by calling the SEC at 1-800-732-0330. In addition, the SEC maintains an Internet website at <http://www.sec.gov> that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC.

We provide electronic access, free of charge, to our periodic and current reports on our Internet website located at <http://www.energytransfer.com>. These reports are available on our website as soon as reasonably practicable after we electronically file such materials with the SEC. Information contained on our website is not part of this report.



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ITEM 1A. RISK FACTORS

In addition to risks and uncertainties in the ordinary course of business that are common to all businesses, important factors that are specific to our structure as a limited partnership, our industry and our company could materially impact our future performance and results of operations. We have provided below a list of these risk factors that should be reviewed when considering an investment in our securities. These are not all the risks we face and other factors currently considered immaterial or unknown to us may impact our future operations.

Risks Inherent in an Investment in Us

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

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

- the amount of natural gas transported in our pipelines and gathering systems;
- the level of throughput in our processing and treating operations;
- the fees we charge and the margins we realize for our gathering, treating, processing, storage and transportation services;
- the price of natural gas and NGLs;
- the relationship between natural gas and NGL prices;
- the amount of cash distributions we receive with respect to the AmeriGas common units that we own;
- the weather in our operating areas;
- the level of competition from other midstream companies, interstate pipeline companies and other energy providers;
- the level of our operating costs;
- prevailing economic conditions; and
- the level of our derivative activities.

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

- the level of capital expenditures we make;
- the level of costs related to litigation and regulatory compliance matters;
- the cost of acquisitions, if any;
- the levels of any margin calls that result from changes in commodity prices;
- our debt service requirements;
- fluctuations in our working capital needs;
- our ability to borrow under our credit facilities;
- our ability to access capital markets;
- restrictions on distributions contained in our debt agreements; and
- the amount, if any, of cash reserves established by our General Partner in its discretion for the proper conduct of our business.

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

Furthermore, Unitholders should be aware that the amount of cash we have available for distribution depends primarily upon our cash flow, and is not solely a function of profitability, which is affected by non-cash items. As a result, we may declare and/or pay cash distributions during periods when we record net losses.

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

Our Second Amended and Restated Agreement of Limited Partnership (the “Partnership Agreement”) allows us to issue an unlimited number of additional limited partner interests, including securities senior to the Common Units, without the approval of our Unitholders. The issuance of additional Common Units or other equity securities will have the following effects:

- the current proportionate ownership interest of our Unitholders in us will decrease;
- the amount of cash available for distribution on each Common Unit or partnership security may decrease;
- the relative voting strength of each previously outstanding Common Unit may be diminished; and
- the market price of the Common Units or partnership securities may decline.

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

As of December 31, 2011, ETE owned 50,226,967 ETP Common Units and SUG, as a subsidiary of ETE, is expected to receive \$105 million of additional ETP Common Units upon consummation of the Citrus Acquisition. If ETE were to sell and/or distribute its Common Units to the holders of its equity interests in the future, those holders may dispose of some or all of these units. The sale or disposition of a substantial portion of these units in the public markets could reduce the market price of our outstanding Common Units.

In August 2009, we filed a registration statement to register 12,000,000 ETP Common Units held by ETE, which allows ETE to offer and sell these ETP Common Units from time to time in one or more public offerings, direct placements or by other means.

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

As of December 31, 2011, we had approximately \$7.81 billion of consolidated debt, excluding the credit facilities of our joint ventures. Our level of indebtedness affects our operations in several ways, including, among other things:

- a significant portion of our cash flow from operations will be dedicated to the payment of principal and interest on outstanding debt and will not be available for other purposes, including payment of distributions;
- covenants contained in our existing debt agreements require us to meet financial tests that may adversely affect our flexibility in planning for and reacting to changes in our business;
- our ability to obtain additional financing for working capital, capital expenditures, acquisitions and general partnership purposes may be limited;
- we may be at a competitive disadvantage relative to similar companies that have less debt;
- we may be more vulnerable to adverse economic and industry conditions as a result of our significant debt level; and
- failure to comply with the various restrictive covenants of our debt agreements could negatively impact our ability and the ability of our subsidiaries to incur additional debt, including our ability to utilize the available capacity under our revolving credit facilities, and our ability to pay our distributions.

Construction of new pipeline projects will require significant amounts of debt and equity financing which may not be available to us on acceptable terms, or at all.

We plan to fund our growth capital expenditures, including any new pipeline construction projects we may undertake, with proceeds from sales of our debt and equity securities and borrowings under our revolving credit facility; however, we cannot be certain that we will be able to issue our debt and equity securities on terms satisfactory to us, or at all. If we are unable to finance our expansion projects as expected, we could be required to seek alternative financing, the terms of which may not be attractive to us, or to revise or cancel our expansion plans.

As of December 31, 2011, we had approximately \$7.81 billion of consolidated debt, excluding the credit facilities of our joint ventures. A significant increase in our indebtedness that is proportionately greater than our issuances of equity could negatively impact our credit ratings or our ability to remain in compliance with the financial covenants under our revolving credit agreement, which could have a material adverse effect on our financial condition, results of operations and cash flows.

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Increases in interest rates could adversely affect our business, results of operations, cash flows and financial condition. In addition to our exposure to commodity prices, we have exposure to changes in interest rates. As of December 31, 2011, we had approximately \$7.81 billion of consolidated debt, excluding the credit facilities of our joint ventures. Approximately \$314.4 million of our consolidated debt bears interest at variable interest rates and the remainder bears interest at fixed rates. To the extent that we have debt with floating interest rates, our results of operations, cash flows and financial condition could be materially adversely affected by increases in interest rates. We manage a portion of our interest rate exposures by utilizing interest rate swaps.

As of December 31, 2011, we had a total of \$1.15 billion of notional amount of forward-starting interest rate swaps outstanding to hedge the anticipated issuance of senior notes in 2012 and 2013. In addition, we had a total of \$500 million of notional amount of interest rate swaps that swap a portion of our fixed rate debt to floating.

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

The credit and risk profile of our General Partner and its owners could adversely affect our credit ratings and profile. The credit and business risk profiles of our General Partner, and of ETE as the indirect owner of our General Partner, may be factors in credit evaluations of us as a publicly traded limited partnership due to the significant influence of our General Partner and ETE over our business activities, including our cash distributions, acquisition strategy and business risk profile. Another factor that may be considered is the financial condition of our General Partner and its owners, including the degree of their financial leverage and their dependence on cash flow from the Partnership to service their indebtedness.

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

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

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

Furthermore, if the Unitholders are dissatisfied with the performance of our General Partner, they will have little ability to remove our General Partner. The General Partner generally may not be removed except upon the vote of the holders of 66 2/3% of the outstanding units voting together as a single class, including units owned by the General Partner and its affiliates. As of December 31, 2011, ETE and its affiliates held approximately 22% of our outstanding units, with an additional approximate 1% of our outstanding units held by our officers and directors. Consequently, it could be difficult to remove the General Partner without the consent of the General Partner and our related parties.

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

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

The General Partner may transfer its general partner interest to a third party without the consent of the Unitholders.

Furthermore, the general partner of our General Partner may transfer its general partner interest in our General Partner to a third party without the consent of the Unitholders. Any new owner of the General Partner or the general partner of the General Partner would be in a position to replace the officers of the General Partner with its own choices and to

control the decisions taken by such officers.

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

If at any time less than 20% of the outstanding units of any class are held by persons other than the General Partner and its affiliates, the General Partner will have the right to acquire all, but not less than all, of those units at a price no less than their then-current

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market price. As a consequence, a Unitholder may be required to sell his Common Units at an undesirable time or price. The General Partner may assign this purchase right to any of its affiliates or to us.

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

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

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

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

Unitholders may have liability to repay distributions.

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

We have a holding company structure in which our subsidiaries conduct our operations and own our operating assets. We are a holding company, and our subsidiaries conduct all of our operations and own all of our operating assets. We do not have significant assets other than the partnership interests and the equity in our subsidiaries. As a result, our ability to make required payments on the notes depends on the performance of our subsidiaries and their ability to distribute funds to us. The ability of our subsidiaries to make distributions to us may be restricted by, among other things, credit facilities and applicable state partnership laws and other laws and regulations. If we are unable to obtain the funds necessary to pay the principal amount at maturity of the notes, we may be required to adopt one or more alternatives, such as a refinancing of the notes. We cannot assure you that we would be able to refinance the notes. We do not have the same flexibility as other types of organizations to accumulate cash, which may limit cash available to service the notes or to repay them at maturity.

Unlike a corporation, our partnership agreement requires us to distribute, on a quarterly basis, 100% of our Available Cash to our Unitholders of record and our General Partner. Available Cash is generally all of our cash on hand as of the end of a quarter, adjusted for cash distributions and net changes to reserves. Our General Partner will determine the amount and timing of such distributions and has broad discretion to establish and make additions to our reserves or the reserves of our operating subsidiaries in amounts it determines in its reasonable discretion to be necessary or appropriate:

- to provide for the proper conduct of our business and the businesses of our operating subsidiaries (including reserves for future capital expenditures and for our anticipated future credit needs);
- to provide funds for distributions to our Unitholders and our General Partner for any one or more of the next four calendar quarters; or
- to comply with applicable law or any of our loan or other agreements.



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### Risks Related to Conflicts of Interest

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

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

- permits our General Partner to make a number of decisions in its "sole discretion." This entitles our General Partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner;
- provides that our General Partner is entitled to make other decisions in its "reasonable discretion;"
- generally provides that affiliated transactions and resolutions of conflicts of interest not involving a required vote of Unitholders must be "fair and reasonable" to us and that, in determining whether a transaction or resolution is "fair and reasonable," our General Partner may consider the interests of all parties involved, including its own. Unless our General Partner has acted in bad faith, the action taken by our General Partner shall not constitute a breach of its fiduciary duty; and
- provides that our General Partner and its officers and directors will not be liable for monetary damages to us, our limited partners or assignees for errors of judgment or for any acts or omissions if our General Partner and those other persons acted in good faith.

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

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

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

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

Our Partnership Agreement requires the General Partner to deduct from operating surplus cash reserves that in its reasonable discretion are necessary to fund our future operating expenditures. In addition, our Partnership Agreement permits the General Partner to reduce available cash by establishing cash reserves for the proper conduct of our business, to comply with applicable law or agreements to which we are a party or to provide funds for future distributions to partners. These cash reserves will affect the amount of cash available for distribution to Unitholders. Our General Partner has conflicts of interest and limited fiduciary responsibilities that may permit our General Partner to favor its own interests to the detriment of Unitholders.

ETE indirectly owns our General Partner and as a result controls us. ETE also owns the general partner of Regency, a publicly traded partnership with which we compete in the natural gas gathering, processing and transportation business. The directors and officers of our General Partner and its affiliates have fiduciary duties to manage our General Partner in a manner that is beneficial to ETE, the sole owner of our General Partner. At the same time, our General Partner has fiduciary duties to manage us in a manner that is beneficial to our Unitholders. Therefore, our General Partner's duties to us may conflict with the duties of its officers and directors to ETE as its sole owner. As a result of these conflicts of interest, our General Partner may favor its own interest or those of ETE, Regency or their owners or affiliates over the interest of our Unitholders.

Such conflicts may arise from, among others, the following:

Our Partnership Agreement limits the liability and reduces the fiduciary duties of our General Partner while also restricting the remedies available to our Unitholders for actions that, without these limitations, might constitute breaches of fiduciary duty. Unitholders are deemed to have consented to some actions and conflicts of interest that

might otherwise be deemed a breach of fiduciary or other duties under applicable state law. Our General Partner is allowed to take into account the interests of parties in addition to us in resolving conflicts of interest, thereby limiting its fiduciary duties to us.



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Our General Partner is allowed to take into account the interests of parties in addition to us, including ETE, Regency and their affiliates, in resolving conflicts of interest, thereby limiting its fiduciary duties to us.

Our General Partner's affiliates, including ETE, Regency and their affiliates, are not prohibited from engaging in other businesses or activities, including those in direct competition with us.

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

Neither our Partnership Agreement nor any other agreement requires ETE or its affiliates, including Regency, to pursue a business strategy that favors us. The directors and officers of the general partners of ETE and Regency have a fiduciary duty to make decisions in the best interest of their members, limited partners and unitholders, which may be contrary to our best interests.

Some of the directors and officers of ETE who provide advice to us also may devote significant time to the businesses of ETE, Regency and their affiliates and will be compensated by them for their services.

Our General Partner determines which costs, including allocated overhead costs, are reimbursable by us.

Our General Partner is allowed to resolve any conflicts of interest involving us and our General Partner and its affiliates, and any resolution of a conflict of interest by our General Partner that is fair and reasonable to us will be deemed approved by all partners and will not constitute a breach of the partnership agreement.

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

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

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

Our General Partner intends to limit its liability regarding our contractual and other obligations and, in some circumstances, may be entitled to be indemnified by us.

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

In addition, certain conflicts may arise as a result of our pursuing acquisitions or development opportunities that may also be advantageous to Regency. If we are limited in our ability to pursue such opportunities, we may not realize any or all of the commercial value of such opportunities. In addition, if Regency is allowed access to our information concerning any such opportunity and Regency uses this information to pursue the opportunity to our detriment, we may not realize any of the commercial value of this opportunity. In either of these situations, our business, results of operations and the amount of our distributions to our Unitholders may be adversely affected. We cannot assure Unitholders that such conflicts will not occur or that our internal conflicts policy will be effective in all circumstances to protect our commercially sensitive information or to realize the commercial value of our business opportunities.

Affiliates of our General Partner may compete with us.

Except as provided in our Partnership Agreement, affiliates and related parties of our General Partner are not prohibited from engaging in other businesses or activities, including those that might be in direct competition with us. Regency competes with us with respect to our natural gas operations. Additionally, two directors of Regency GP LLC currently serve as directors of LE GP, LLC, the general partner of ETE.

### Risks Related to Our Business

We do not control, and therefore may not be able to cause or prevent certain actions by, certain of our joint ventures. Certain of our joint ventures have their own governing boards, and we may not control all of the decisions of those boards. Consequently, it may be difficult or impossible for us to cause the joint venture entity to take actions that we believe would be in our or the joint venture's best interests. Likewise, we may be unable to prevent actions of the joint venture.

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

The risks of nonpayment and nonperformance by our customers are a major concern in our business. Participants in the energy industry have been subjected to heightened scrutiny from the financial markets in light of past collapses

and failures of other

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energy companies. We are subject to risks of loss resulting from nonpayment or nonperformance by our customers. The current tightening of credit in the financial markets may make it more difficult for customers to obtain financing and, depending on the degree to which this occurs, there may be a material increase in the nonpayment and nonperformance by our customers. Any substantial increase in the nonpayment and nonperformance by our customers could have a material effect on our results of operations and operating cash flows.

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

Income from our midstream and intrastate transportation and storage operations is exposed to risks due to fluctuations in commodity prices. For a portion of the natural gas gathered at the North Texas System, Southeast Texas System and HPL System, we purchase natural gas from producers at the wellhead and then gather and deliver the natural gas to pipelines where we typically resell the natural gas under various arrangements, including sales at index prices.

Generally, the gross margins we realize under these arrangements decrease in periods of low natural gas prices. For a portion of the natural gas gathered and processed at the North Texas System and Southeast Texas System, we enter into percent-of-proceeds arrangements, keep-whole arrangements, and processing fee agreements pursuant to which we agree to gather and process natural gas received from the producers. Under percent-of-proceeds arrangements, we generally sell the residue gas and NGLs at market prices and remit to the producers an agreed upon percentage of the proceeds based on an index price. In other cases, instead of remitting cash payments to the producer, we deliver an agreed upon percentage of the residue gas and NGL volumes to the producer and sell the volumes we keep to third parties at market prices. Under these arrangements, our revenues and gross margins decline when natural gas prices and NGL prices decrease. Accordingly, a decrease in the price of natural gas or NGLs could have an adverse effect on our results of operations. Under keep-whole arrangements, we generally sell the NGLs produced from our gathering and processing operations to third parties at market prices. Because the extraction of the NGLs from the natural gas during processing reduces the Btu content of the natural gas, we must either purchase natural gas at market prices for return to producers or make a cash payment to producers equal to the value of this natural gas. Under these arrangements, our revenues and gross margins decrease when the price of natural gas increases relative to the price of NGLs if we are not able to bypass our processing plants and sell the unprocessed natural gas. Under processing fee agreements, we process the gas for a fee. If recoveries are less than those guaranteed to the producer, we may suffer a loss by having to supply liquids or its cash equivalent to keep the producer whole with regard to contractual recoveries.

In the past, the prices of natural gas and NGLs have been extremely volatile, and we expect this volatility to continue. For example, during the year ended December 31, 2011, the NYMEX settlement price for the prompt month contract ranged from a high of \$4.38 per MMBtu to a low of \$3.36 per MMBtu. A composite of the Mt. Belvieu average NGLs price based upon our average NGLs composition during our year ended December 31, 2011 ranged from a high of approximately \$1.36 per gallon to a low of approximately \$1.15 per gallon.

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

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

- the impact of weather on the demand for oil and natural gas;
- the level of domestic oil and natural gas production;
- the availability of imported oil and natural gas;

- actions taken by foreign oil and gas producing nations;
- the availability of local, intrastate and interstate transportation systems;
- the price, availability and marketing of competitive fuels;
- the demand for electricity;

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the impact of energy conservation efforts; and  
the extent of governmental regulation and taxation.

The profitability of certain activities in our NGL and refined products storage business, our NGL transportation business and our off-gas processing and fractionating business are largely dependent upon market demand for NGLs and refined products, which has been volatile, and competition in the market place, both of which are factors that are beyond our control.

Our NGL and refined products storage revenues are primarily derived from fixed capacity arrangements between us and our customers. However, a portion of our revenue is derived from fungible storage and throughput arrangements, under which our revenue is more dependent upon demand for storage from our customers. Demand for these services may fluctuate as a result of changes in commodity prices. Our NGL and refined products storage assets are primarily located in the Mont Belvieu area, which is a significant storage distribution and trading complex with multiple industry participants, any one of which could compete for the business of our existing and potential customers. Any loss of business from existing customers or our inability to attract new customers could have an adverse effect on our results of operations.

Revenue from our NGL transportation systems is exposed to risks due to fluctuations in demand for transportation as a result of unfavorable commodity prices and competition from nearby pipelines. We receive substantially all of our transportation revenues through dedicated contracts under which the customer agrees to deliver the total output from particular processing plants that are connected only to our transportation system. We may not be able to renew these contracts or execute new customer contracts on favorable terms if NGL prices decline and demand for our transportation services decreases. Any loss of existing customers due to decreased demand for our services or competition from other transportation service providers could have a negative impact on our revenues and have an adverse effect on our results of operations.

Revenue from our off-gas processing and fractionating system in south Louisiana is exposed to risks due to the low concentration of suppliers near our facilities and the possibility that connected refineries may not provide us with sufficient off-gas for processing at our facilities. The connected refineries may also experience outages due to maintenance issues and severe weather, such as hurricanes. We receive revenues primarily through customer agreements that are a combination of keep-whole and percent-of-proceeds arrangements, as well as from transportation and fractionation fees. Consequently, a large portion of our off-gas processing and fractionation revenue is exposed to risks due to fluctuations in commodity prices. In addition, a decline in NGL prices could cause a decrease in demand for our off-gas processing and fractionation services and could have an adverse effect on our results of operations.

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

- the impact of weather on the demand for oil, natural gas and NGLs;
- the level of domestic oil and natural gas production;
- the availability of imported oil, natural gas and NGLs;
- actions taken by foreign oil and gas producing nations;
- the availability of local transportation systems;
- the price, availability and marketing of competitive fuels;
- the demand for electricity;
- the impact of energy conservation efforts; and
- the extent of governmental regulation and taxation.

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

From time to time, we have sought to limit a portion of the adverse effects resulting from changes in natural gas and other commodity prices and interest rates by using derivative financial instruments and other risk management mechanisms and by our trading, marketing and/or system optimization activities. To the extent that we hedge our commodity price and interest rate exposures, we forego the benefits we would otherwise experience if commodity prices or interest rates were to change in our favor. In addition, even though monitored by management, our

derivatives activities can result in losses. Such losses could occur under various circumstances, including if a counterparty does not perform its obligations under the derivative arrangement, the hedge is imperfect, commodity prices move unfavorably related to our physical or financial positions or hedging policies and procedures are not followed.

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

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

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

A substantial portion of our assets, including our gathering systems and our processing and treating plants, are connected to natural gas reserves and wells for which the production will naturally decline over time. Accordingly, our cash flows will also decline unless we are able to access new supplies of natural gas by connecting additional production to these systems.

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

Our interstate segment derives a significant portion of its revenue from charging its customers for reservation of capacity, which revenues it receives regardless of whether these customers actually use the reserved capacity. Our interstate segment also generates revenue from transportation of natural gas for customers without reserved capacity. If the reserves available through the supply basins connected to our interstate pipelines decline, a decrease in development or production activity could cause a decrease in the volume of natural gas available for transmission or a decrease in demand for natural gas transportation on our interstate pipelines over the long run.

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

We may not be able to fully execute our growth strategy if we encounter increased competition for qualified assets. Our strategy contemplates growth through the development and acquisition of a wide range of midstream, transportation, storage, and other energy infrastructure assets while maintaining a strong balance sheet. This strategy includes constructing and acquiring additional assets and businesses to enhance our ability to compete effectively and diversify our asset portfolio, thereby providing more stable cash flow. We regularly consider and enter into discussions regarding, and are currently contemplating, the acquisition of additional assets and businesses, stand alone development projects or other transactions that we believe will present opportunities to realize synergies and increase

our cash flow.

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

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

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

As of December 31, 2011, our consolidated balance sheet reflected \$1.22 billion of goodwill and \$331.4 million of intangible assets. Goodwill is recorded when the purchase price of a business exceeds the fair value of the tangible and separately measurable intangible net assets. Accounting principles generally accepted in the United States require us to test goodwill for impairment on an annual basis or when events or circumstances occur, indicating that goodwill might be impaired. Long-lived assets such as intangible assets with finite useful lives are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. If we determine that any of our goodwill or intangible assets were impaired, we would be required to take an immediate charge to earnings with a correlative effect on partners' capital and balance sheet leverage as measured by debt to total capitalization.

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

Our results of operations and our ability to grow and to increase distributions to Unitholders will depend in part on our ability to make acquisitions that are accretive to our distributable cash flow per unit.

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

- because we are unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them;

- because we are unable to raise financing for such acquisitions on economically acceptable terms; or

- because we are outbid by competitors, some of which are substantially larger than us and have greater financial resources and lower costs of capital than we do.

Furthermore, even if we consummate acquisitions that we believe will be accretive, those acquisitions may in fact adversely affect our results of operations or result in a decrease in distributable cash flow per unit. Any acquisition involves potential risks, including the risk that we may:

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

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

- significantly increase our interest expense or financial leverage if we incur additional debt to finance acquisitions;

- encounter difficulties operating in new geographic areas or new lines of business;

- incur or assume unanticipated liabilities, losses or costs associated with the business or assets acquired for which we are not indemnified or for which the indemnity is inadequate;

- be unable to hire, train or retrain qualified personnel to manage and operate our growing business and assets;

- less effectively manage our historical assets, due to the diversion of management's attention from other business concerns; or

- incur other significant charges, such as impairment of goodwill or other intangible assets, asset devaluation or restructuring charges.

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

If we do not continue to construct new pipelines, our future growth could be limited.

During the past several years, we have constructed several new pipelines, and are currently involved in constructing several new pipelines. Our results of operations and ability to grow and to increase distributable cash flow per unit will depend, in part, on our ability to construct pipelines that are accretive to our distributable cash flow. We may be unable to construct pipelines that are accretive to distributable cash flow for any of the following reasons, among others:

- we are unable to identify pipeline construction opportunities with favorable projected financial returns;

- we are unable to raise financing for our identified pipeline construction opportunities; or



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we are unable to secure sufficient natural gas transportation commitments from potential customers due to competition from other pipeline construction projects or for other reasons.

Furthermore, even if we construct a pipeline that we believe will be accretive, the pipeline may in fact adversely affect our results of operations or results from those projected prior to commencement of construction and other factors.

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

One of the ways that we have grown our business is through the construction of additions to our existing gathering, compression, treating, processing and transportation systems. The construction of a new pipeline or the expansion of an existing pipeline, by adding additional compression capabilities or by adding a second pipeline along an existing pipeline, and the construction of new processing or treating facilities, involve numerous regulatory, environmental, political and legal uncertainties beyond our control and require the expenditure of significant amounts of capital that we will be required to finance through borrowings, the issuance of additional equity or from operating cash flow. If we undertake these projects, they may not be completed on schedule, at all, or at the budgeted cost. A variety of factors outside our control, such as weather, natural disasters and difficulties in obtaining permits and rights-of-way or other regulatory approvals, as well as the performance by third party contractors, may result in increased costs or delays in construction. Cost overruns or delays in completing a project could have a material adverse effect on our results of operations and cash flows. Moreover, our revenues may not increase immediately following the completion of a particular project. For instance, if we build a new pipeline, the construction will occur over an extended period of time, but we may not materially increase our revenues until long after the project's completion. In addition, the success of a pipeline construction project will likely depend upon the level of natural gas exploration and development drilling activity and the demand for pipeline transportation in the areas proposed to be serviced by the project as well as our ability to obtain commitments from producers in this area to utilize the newly constructed pipelines. In this regard, we may construct facilities to capture anticipated future growth in natural gas production in a region in which such growth does not materialize. As a result, new facilities may be unable to attract enough throughput or contracted capacity reservation commitments to achieve our expected investment return, which could adversely affect our results of operations and financial condition.

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

For the year ended December 31, 2011, EnCana Oil and Gas (USA), Inc., Rosetta Resources Operating LP, EnerVest Operating, LLC, and SandRidge Energy Inc. supplied us with approximately 67% of the Southeast Texas System's natural gas supply. For our year ended December 31, 2011, EOG Resources, Inc., affiliates of Chesapeake Energy Corporation, XTO Energy Inc. ("XTO") and EnCana Oil and Gas (USA), Inc., supplied us with approximately 76% of the North Texas System's natural gas supply. We are not the only option available to these producers for disposition of the natural gas they produce. To the extent that these and other producers may reduce the volumes of natural gas that they supply us, we would be adversely affected unless we were able to acquire comparable supplies of natural gas from other producers.

We depend on key customers to transport natural gas through our pipelines.

We have several nine- and ten-year fee-based transportation contracts with XTO that terminate through 2019, pursuant to which XTO has committed to transport certain minimum volumes of natural gas on pipelines in our ET Fuel System. We also have an eight-year fee-based transportation contract with Luminant Energy Company LLC ("Luminant") to transport natural gas on the ET Fuel System. We have also entered into two eight-year natural gas storage contracts that terminate in 2012 with Luminant to store natural gas at the two natural gas storage facilities that are part of the ET Fuel System. Each of the contracts with Luminant may be extended by Luminant for two additional five-year terms.

During 2011 Natural Gas Exchange, Inc., EDF Trading North America, Inc., XTO Energy, Inc. and ConocoPhillips collectively accounted for approximately 30% of our intrastate transportation and storage revenues.

With respect to our interstate transportation operations, FEP, an entity in which we own a 50% interest, has 10-12 year agreements from a small number of major shippers for approximately 1.85 Bcf/d of firm transportation service on the 2.0 Bcf/d Fayetteville Express pipeline project. In connection with our Tiger pipeline, we have an agreement with Chesapeake Energy Marketing, Inc. that provides for a 15-year commitment for firm transportation capacity of

approximately 1.0 Bcf/d. We also have agreements with other shippers that provide for 10-year commitments for firm transportation capacity on the Tiger pipeline totaling approximately 1.4 Bcf/d, bringing the total shipper commitments to approximately 2.4 Bcf/d of firm transportation service in the Tiger pipeline project. Transwestern generates the majority of its revenues from long-term and short-term firm transportation contracts with natural gas producers, local distribution companies and end-users.

During 2011, Chesapeake Energy Marketing, Inc., EnCana Marketing (USA), Inc. (“EnCana”), Shell Energy North America (US), L.P. and Pacific Summit Energy LLC collectively accounted for 37% of our interstate revenues.

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The failure of the major shippers on our intrastate and interstate transportation pipelines to fulfill their contractual obligations could have a material adverse effect on our cash flow and results of operations if we were not able to replace these customers under arrangements that provide similar economic benefits as these existing contracts. Certain of our assets may become subject to regulation.

Intrastate transportation of NGLs is largely regulated by the state in which such transportation takes place. The West Texas Pipeline, which we acquired as part the LDH acquisition, transports NGLs within the state of Texas and is subject to regulation by the TRRC. This NGL transportation system offers services pursuant to an intrastate transportation tariff on file with the TRRC. Such services must be provided in a manner that is just, reasonable and non-discriminatory. We believe that this NGL system does not currently provide interstate service and that it is thus not subject to FERC jurisdiction under the Interstate Commerce Act (the "ICA") and the Energy Policy Act of 1992. We cannot guarantee that the jurisdictional status of this NGL pipeline system will remain unchanged. If the West Texas Pipeline became subject to regulation by the FERC, pursuant to the ICA, the FERC's rate-making methodologies may, among other things, delay the use of rates that reflect increased costs and subject us to potentially burdensome and expensive operational, reporting and other requirements. Any of the foregoing could adversely affect revenues and cash flow related to these assets.

Federal, state or local regulatory measures could adversely affect the business and operations of our midstream and intrastate assets.

Our midstream and intrastate transportation and storage operations are generally exempt from FERC regulation under the NGA, but FERC regulation still significantly affects our business and the market for our products. The rates, terms and conditions of some of the transportation and storage services we provide on the HPL System, the East Texas pipeline, the Oasis pipeline and the ET Fuel System are subject to FERC regulation under Section 311 of the NGPA. Under Section 311, rates charged for transportation and storage must be fair and equitable amounts. Amounts collected in excess of fair and equitable rates are subject to refund with interest, and the terms and conditions of service, set forth in the pipeline's statement of operating conditions, are subject to FERC review and approval. Should the FERC determine not to authorize rates equal to or greater than our currently approved rates, we may suffer a loss of revenue. Failure to observe the service limitations applicable to storage and transportation service under Section 311, and failure to comply with the rates approved by the FERC for Section 311 service, and failure to comply with the terms and conditions of service established in the pipeline's FERC-approved statement of operating conditions could result in an alteration of jurisdictional status and/or the imposition of administrative, civil and criminal penalties.

FERC has adopted market-monitoring and annual and quarterly reporting regulations, which regulations are applicable to many intrastate pipelines as well as other entities that are otherwise not subject to FERC's NGA jurisdiction, such as natural gas marketers. These regulations are intended to increase the transparency of wholesale energy markets, to protect the integrity of such markets, and to improve FERC's ability to assess market forces and detect market manipulation. These regulations may result in administrative burdens and additional compliance costs for us.

We hold transportation contracts with interstate pipelines that are subject to FERC regulation. As a shipper on an interstate pipeline, we are subject to FERC requirements related to use of the interstate capacity. Any failure on our part to comply with the FERC's regulations or orders could result in the imposition of administrative, civil and criminal penalties.

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

Our midstream and intrastate transportation operations are also subject to ratable take and common purchaser statutes in Texas, New Mexico, Arizona, Louisiana, Utah and Colorado. Ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling.

Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes have the effect of restricting our right as an owner of gathering facilities to decide with whom we contract to purchase or transport natural gas. Federal law leaves any economic regulation of natural gas gathering to the states, and some of the states in which we operate have adopted complaint-based or other limited economic regulation of natural gas gathering activities. States in which we operate that have adopted some form of complaint-based regulation, like Texas, generally allow natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering rates and access. Other state and local regulations also affect our business.

Our storage facilities are also subject to the jurisdiction of the TRRC. Generally, the TRRC has jurisdiction over all underground storage of natural gas in Texas, unless the facility is part of an interstate gas pipeline facility. Because the natural gas storage

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facilities of the ET Fuel System and HPL System are only connected to intrastate gas pipelines, they fall within the TRRC's jurisdiction and must be operated pursuant to TRRC permit. Certain changes in ownership or operation of TRRC-jurisdictional storage facilities, such as facility expansions and increases in the maximum operating pressure, must be approved by the TRRC through an amendment to the facility's existing permit. In addition, the TRRC must approve transfers of the permits. Texas laws and regulations also require all natural gas storage facilities to be operated to prevent waste, the uncontrolled escape of gas, pollution and danger to life or property. Accordingly, the TRRC requires natural gas storage facilities to implement certain safety, monitoring, reporting and record-keeping measures.

Violations of the terms and provisions of a TRRC permit or a TRRC order or regulation can result in the modification, cancellation or suspension of an operating permit and/or civil penalties, injunctive relief, or both.

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

Failure to comply with applicable laws and regulations could result in the imposition of administrative, civil and criminal remedies.

Our interstate pipelines are subject to laws, regulations and policies governing the rates they are allowed to charge for their services.

Laws, regulations and policies governing interstate natural gas pipeline rates could affect the ability of our interstate pipelines to establish rates, to charge rates that would cover future increases in its costs, or to continue to collect rates that cover current costs. NGA-jurisdictional natural gas companies must charge rates that are deemed just and reasonable by the FERC. The rates charged by natural gas companies are generally required to be on file with the FERC in FERC-approved tariffs. Pursuant to the NGA, existing tariff rates may be challenged by complaint and rate increases proposed by the natural gas company may be challenged by protest. We also may be limited by the terms of negotiated rate agreements from seeking future rate increases, or constrained by competitive factors from charging our FERC-approved maximum just and reasonable tariff rates. Further, the FERC has the ability, on a prospective basis, to order refunds of amounts collected under rates that have been found by the FERC to be in excess of a just and reasonable level.

On September 21, 2011, in lieu of filing a new general rate case filing under Section 4 of the NGA, Transwestern filed a proposed settlement with the FERC, which was approved by the FERC on October 31, 2011. Transwestern is required to file a new general rate case on October 1, 2014. However, shippers which were not parties to the settlement have the right to challenge the lawfulness of tariff rates that have become final and effective. The FERC may also investigate such rates absent shipper complaint.

Some of the shippers on our interstate pipelines pay rates established pursuant to long-term, negotiated rate transportation agreements. Prospective shippers on our interstate pipelines that elect not to pay a negotiated rate for service may instead choose to pay a cost-based recourse rate. Negotiated rate agreements generally provide a degree of certainty to the pipeline and shipper as to a fixed rate during the term of the relevant transportation agreement, but such agreements can limit the pipeline's future ability to collect costs associated with construction and operation of the pipeline that might be higher than anticipated at the time the negotiated rate agreement was entered.

Any successful challenge to the rates of our interstate natural gas companies, whether the result of a complaint, protest or investigation, could reduce our revenues associated with providing transportation services on a prospective basis. We cannot guarantee that our interstate pipelines will be able to recover all of their costs through existing or future rates.

The ability of interstate pipelines held in tax-pass-through entities, like us, to include an allowance for income taxes in their regulated rates has been subject to extensive litigation before the FERC and the courts, and the FERC's current policy is subject to future refinement or change.

The ability of interstate pipelines held in tax-pass-through entities, like us, to include an allowance for income taxes as a cost-of-service element in their regulated rates has been subject to extensive litigation before the FERC and the

courts for a number of years. It is currently the FERC's policy to permit pipelines to include in cost-of-service a tax allowance to reflect actual or potential income tax liability on their public utility income attributable to all partnership or limited liability company interests, if the ultimate owner of the interest has an actual or potential income tax liability on such income. Whether a pipeline's owners have such actual or potential income tax liability will be reviewed by the FERC on a case-by-case basis. Under the FERC's policy, we thus remain eligible to include an income tax allowance in the tariff rates we charge for interstate natural gas transportation. The application of that policy remains subject to future refinement or change by the FERC. With regard to rates charged and collected by Transwestern, the allowance for income taxes as a cost-of-service element in our tariff rates is generally not subject to challenge prior to the end of the term of our 2011 rate case settlement.



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The interstate pipelines are subject to laws, regulations and policies governing terms and conditions of service, which could adversely affect their business and operations.

In addition to rate oversight, the FERC's regulatory authority extends to many other aspects of the business and operations of our interstate pipelines, including:

- terms and conditions of service;
- the types of services interstate pipelines may offer their customers;
- construction of new facilities;
- acquisition, extension or abandonment of services or facilities;
- reporting and information posting requirements;
- accounts and records; and
- relationships with affiliated companies involved in all aspects of the natural gas and energy businesses.

Compliance with these requirements can be costly and burdensome. Future changes to laws, regulations and policies in these areas may impair the ability of our interstate pipelines to compete for business, may impair their ability to recover costs or may increase the cost and burden of operation.

We must on occasion rely upon rulings by the FERC or other governmental authorities to carry out certain of our business plans. For example, in order to carry out our plan to construct the Fayetteville Express and Tiger pipelines we were required to, among other things, file and support before the FERC NGA Section 7(c) applications for certificates of public convenience and necessity to build, own and operate such facilities. We cannot guarantee that FERC will authorize construction and operation of any future interstate natural gas transportation project we might propose. Moreover, there is no guarantee that certificate authority for any future interstate projects will be granted in a timely manner or will be free from potentially burdensome conditions.

Failure to comply with all applicable FERC-administered statutes, rules, regulations and orders, could bring substantial penalties and fines. Under the Energy Policy Act of 2005, the FERC has civil penalty authority under the NGA to impose penalties for current violations of up to \$1.0 million per day for each violation. The FERC possesses similar authority under the NGPA.

Finally, we cannot give any assurance regarding the likely future regulations under which we will operate our interstate pipelines or the effect such regulation could have on our business, financial condition and results of operations.

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

Our natural gas and NGL operations are subject to stringent federal, state, and local laws and regulations that seek to protect human health and the environment, including those governing the emission or discharge of materials into the environment. These laws and regulations may require the acquisition of permits for our operations, result in capital expenditures to manage, limit or prevent emissions, discharges or releases of various materials from our pipelines, plants and facilities and impose substantial liabilities for pollution resulting from our operations. Several governmental authorities, such as the EPA, have the power to enforce compliance with these laws and regulations and the permits issued under them and frequently mandate difficult and costly remediation measures and other actions.

Failure to comply with these laws, regulations and permits may result in the assessment of significant administrative, civil and criminal penalties, the imposition of remedial obligations, and the issuance of injunctive relief.

We may incur substantial environmental costs and liabilities because of the underlying risk inherent to our operations. Certain environmental laws and regulations can provide for joint and several strict liability for cleanup to address discharges or releases of petroleum hydrocarbons or other materials or wastes at sites to which we may have sent wastes or on, under or from our properties and facilities, many of which have been used for industrial activities for a number of years, even if such discharges were caused by our predecessors. Private parties, including the owners of properties through which our gathering systems pass or facilities where our petroleum hydrocarbons or wastes are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations, personal injury or property damage. The total accrued future estimated cost of remediation activities relating to our Transwestern pipeline operations expected to continue through 2025 was \$5.7 million as of December 31, 2011.

Changes in environmental laws and regulations occur frequently, and any such changes that result in more stringent and costly waste handling, emission standards, or storage, transport, disposal or remediation requirements could have a material adverse effect on our operations or financial position. For example, the EPA in 2008 lowered the federal ozone standard from 0.08 ppm to 0.075 ppm, requiring the environmental agencies in states with areas that do not currently meet this standard to adopt new rules between to further reduce NOx and other ozone precursor emissions. We have previously been able to satisfy the more stringent

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NOx emission reduction requirements that affect our compressor units in ozone non-attainment areas at reasonable cost, but there is no guarantee that the changes we may have to make in the future to meet the new ozone standard or other evolving standards will not require us to incur costs that could be material to our operations.

Recently proposed rules regulating air emissions from oil and natural gas operations could cause us to incur increased capital expenditures and operating costs, which may be significant.

On July 28, 2011, the U.S. Environmental Protection Agency ("EPA") proposed rules that would establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, EPA's proposed rule package includes New Source Performance Standards ("NSPS") to address emissions of sulfur dioxide and volatile organic compounds ("VOCs"), and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The EPA's proposal would require the reduction of VOC emissions from oil and natural gas production facilities by mandating the use of "green completions" for hydraulic fracturing, which requires the operator to recover rather than vent the gas and natural gas liquids that come to the surface during completion of the fracturing process. The proposed rules also would establish specific requirements regarding emissions from compressors, dehydrators, storage tanks and other production equipment. In addition, the rules would establish new leak detection requirements for natural gas processing plants. The EPA must take final action on the proposed rules by February 28, 2012. If finalized, these rules could require a number of modifications to our operations including the installation of new equipment. Compliance with such rules will be required within three years of publication of the final rules, and it could result in significant costs, including increased capital expenditures and operating costs, which may adversely impact our business. Climate change legislation or regulations restricting emissions of "greenhouse gases" could result in increased operating costs and reduced demand for the natural gas and other hydrocarbon products that we transport, store or otherwise handle in connection with our transportation, storage, and midstream services.

In December 2009, the EPA determined that emissions of carbon dioxide, methane and other "greenhouse gases" present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA has begun adopting and implementing regulations to restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. The EPA recently adopted two sets of rules regulating greenhouse gas emissions under the Clean Air Act, one of which requires a reduction in emissions of greenhouse gases from motor vehicles and the other of which regulates emissions of greenhouse gases from certain large stationary sources, effective January 2, 2011. The EPA's rules relating to emissions of greenhouse gases from large stationary sources of emissions are currently subject to a number of legal challenges, but the federal courts have thus far declined to issue any injunctions to prevent EPA from implementing, or requiring state environmental agencies to implement, the rules.

In addition, the United States Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and almost one-half of the states have already taken legal measures to reduce emissions of greenhouse gases primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall greenhouse gas emission reduction goal.

The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, natural gas or NGLs. Consequently, legislation and regulatory programs to reduce emissions of greenhouse gases could have an adverse effect on our business, financial condition and results of operations.

Some have suggested that one consequence of climate change could be increased severity of extreme weather, such as increased hurricanes and floods. If such effects were to occur, our operations could be adversely affected in various ways, including damages to our facilities from powerful winds or rising waters, or increased costs for insurance.

Another possible consequence of climate change is increased volatility in seasonal temperatures. The market for our

natural gas is generally improved by periods of colder weather and impaired by periods of warmer weather, so any changes in climate could affect the market for the fuels that we produce. Despite the use of the term “global warming” as a shorthand for climate change, some studies indicate that climate change could cause some areas to experience temperatures substantially colder than their historical averages. As a result, it is difficult to predict how the market for our fuels could be affected by increased temperature volatility, although if there is an overall trend of warmer temperatures, it would be expected to have an adverse effect on our business.

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Any reduction in the capacity of, or the allocations to, our shippers in interconnecting third-party pipelines could cause a reduction of volumes transported in our pipelines, which would adversely affect our revenues and cash flow. Users of our pipelines are dependent upon connections to and from third-party pipelines to receive and deliver natural gas and NGLs. Any reduction in the capacities of these interconnecting pipelines due to testing, line repair, reduced operating pressures, or other causes could result in reduced volumes being transported in our pipelines. Similarly, if additional shippers begin transporting volumes of natural gas and NGLs over interconnecting pipelines, the allocations to existing shippers in these pipelines would be reduced, which could also reduce volumes transported in our pipelines. Any reduction in volumes transported in our pipelines would adversely affect our revenues and cash flow. The recent adoption of financial reform legislation by the United States Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

The United States Congress recently adopted the Dodd-Frank Wall Street Reform and Consumer Protection Act (HR 4173), which, among other provisions, establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The legislation was signed into law by the President on July 21, 2010 and requires the CFTC, the SEC and other regulators to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. In December 2011, the CFTC extended temporary exemptive relief from certain swap regulation provisions of the legislation until July 16, 2012. The CFTC has issued final regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. It is not possible at this time to predict when the CFTC will make these regulations effective. The financial reform legislation may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral, which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure its existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable.

We may be impacted by competition from other midstream and transportation and storage companies.

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

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

access to larger natural gas supplies than we do.

The Transwestern, Fayetteville Express and Tiger pipelines compete with other interstate and intrastate pipeline companies in the transportation and storage of natural gas. The principal elements of competition among pipelines are rates, terms of service, access to sources of supply and the flexibility and reliability of service. Natural gas competes with other forms of energy available to our customers and end-users, including for example, electricity, coal and fuel oils. The primary competitive factor is price. Changes in the availability or price of natural gas and other forms of energy, the level of business activity, conservation, legislation and governmental regulations, the capability to convert to alternate fuels and other factors, including weather and natural gas storage levels, affect the levels of natural gas transportation volumes in the areas served by our pipelines.

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The inability to continue to access tribal lands could adversely affect Transwestern's ability to operate its pipeline system and the inability to recover the cost of right-of-way grants on tribal lands could adversely affect its financial results.

Transwestern's ability to operate its pipeline system on certain lands held in trust by the United States for the benefit of a Native American Tribe, which we refer to as tribal lands, will depend on its success in maintaining existing rights-of-way and obtaining new rights-of-way on those tribal lands. Securing extensions of existing and any additional rights-of-way is also critical to Transwestern's ability to pursue expansion projects. We cannot provide any assurance that Transwestern will be able to acquire new rights-of-way on tribal lands or maintain access to existing rights-of-way upon the expiration of the current grants. Our financial position could be adversely affected if the costs of new or extended right-of-way grants cannot be recovered in rates. Transwestern's existing right-of-way agreements with the Navajo Nation, Southern Ute, Pueblo of Laguna and Fort Mojave tribes extend through November 2029, September 2020, December 2022 and April 2019, respectively.

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

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

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

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

For the year ended December 31, 2011, approximately 31% of our sales of natural gas was to industrial end-users and utilities. As a consequence of the increase in competition in the industry and volatility of natural gas prices, end-users and utilities are increasingly reluctant to enter into long-term purchase contracts. Many end-users purchase natural gas from more than one natural gas company and have the ability to change providers at any time. Some of these end-users also have the ability to switch between gas and alternate fuels in response to relative price fluctuations in the market. Because there are many companies of greatly varying size and financial capacity that compete with us in the marketing of natural gas, we often compete in the end-user and utilities markets primarily on the basis of price. The inability of our management to renew or replace our current contracts as they expire and to respond appropriately to changing market conditions could have a negative effect on our profitability.

Our natural gas storage business may depend on neighboring pipelines to transport natural gas.

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

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

Our pipeline operations are subject to regulation by the DOT, under the PHMSA, pursuant to which the PHMSA has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. Moreover, the PHMSA, through the Office of Pipeline Safety, has promulgated a rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the rule refers to as "high consequence areas."

Activities under these integrity management programs involve the performance of internal pipeline inspections, pressure testing or other effective means to assess the integrity of these regulated pipeline segments, and the regulations require prompt action to address integrity issues raised by the assessment and analysis. Based on the results of our current pipeline integrity testing programs, we estimate that compliance with these federal regulations and analogous state pipeline integrity requirements will result in capital costs of \$3.4 million and operating and maintenance costs of \$17.9 million over the course of the next year. For the years ended December 31, 2011, 2010 and 2009, \$18.3 million, \$13.3 million and \$31.4 million, respectively, of capital costs and \$14.7 million, \$15.4 million and \$18.5 million, respectively, of operating and maintenance costs have been incurred for pipeline integrity testing. Integrity testing and assessment of all of these assets will



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continue, and the potential exists that results of such testing and assessment could cause us to incur even greater capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines.

Changes in other forms of health and safety regulations are also being considered. New pipeline safety legislation requiring more stringent spill reporting and disclosure obligations has been introduced in the U.S. Congress and was passed by the U.S. House of Representatives in 2010, but was not voted on in the U.S. Senate. Similar legislation is likely to be considered in the current session of Congress. The DOT has also recently proposed legislation providing for more stringent oversight of pipelines and increased penalties for violations of safety rules, which is in addition to the PHMSA's announced intention to strengthen its rules. Such Legislative and regulatory changes could have a material effect on our operations through more stringent and comprehensive safety regulations and higher penalties for the violation of those regulations.

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

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

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

As a result of market conditions, premiums and deductibles for certain insurance policies can increase substantially, and in some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. As a result, we may not be able to renew existing insurance policies or procure other desirable insurance on commercially reasonable terms, if at all. If we were to incur a significant liability for which we were not fully insured, it could have a material adverse effect on our financial position and results of operations. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient if such an event were to occur. Terrorist attacks aimed at our facilities could adversely affect our business, results of operations, cash flows and financial condition.

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

We have a significant equity investment in AmeriGas and the value of this investment, and the cash distributions we expect to receive from this investment, are subject to the risks encountered by AmeriGas with respect to its business. In January 2012, we consummated the contribution of the Propane Business to AmeriGas in exchange for consideration of approximately \$1.46 billion in cash and approximately 29.6 million AmeriGas common units, plus the assumption of approximately \$71 million of existing HOLP debt. The value of our investment in AmeriGas common units and the cash distributions we expect to receive on a quarterly basis with respect to these common units are subject to the risks encountered by AmeriGas with respect to its business, including the following:

- adverse weather condition resulting in reduced demand;
- cost volatility and availability of propane, and the capacity to transport propane to its customers;
- the availability of, and its ability to consummate, acquisition or combination opportunities;
- successful integration and future performance of acquired assets or businesses;

- changes in laws and regulations, including safety, tax, consumer protection and accounting matters;
- competitive pressures from the same and alternative energy sources;
- failure to acquire new customers and retain current customers thereby reducing or limiting any increase in revenues;

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- liability for environmental claims;
- increased customer conservation measures due to high energy prices and improvements in energy efficiency and technology resulting in reduced demand;
- adverse labor relations;
- large customer, counter-party or supplier defaults;
  - liability in excess of insurance coverage for personal injury and property damage arising from explosions and other catastrophic events, including acts of terrorism, resulting from operating hazards and risks incidental to transporting, storing and distributing propane, butane and ammonia;
- political, regulatory and economic conditions in the United States and foreign countries;
- capital market conditions, including reduced access to capital markets and interest rate fluctuations;
- changes in commodity market prices resulting in significantly higher cash collateral requirements;
- the impact of pending and future legal proceedings;
- the timing and success of its acquisitions and investments to grow its business; and
- its ability to successfully integrate acquired businesses and achieve anticipated synergies.

Our pipelines may be subject to more stringent safety regulation.

On January 3, 2012, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, became effective. The new law requires more stringent oversight of pipelines and increased civil penalties for violations of pipeline safety rules. The law requires numerous studies and/or the development of rules over the next two years covering the expansion of integrity management, use of automatic and remote-controlled shut-off valves, leak detection systems, sufficiency of existing regulation of gathering pipelines, use of excess flow valves, verification of maximum allowable operating pressure, incident notification, and other pipeline-safety related rules. The DOT has already proposed rules that address many areas of the newly adopted legislation. Any regulatory changes could have a material effect on our operations through more stringent and comprehensive safety regulations and higher penalties for the violation of those regulations.

### Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the IRS were to treat us as a corporation for federal income tax purposes or if we become subject to a material amount of entity-level taxation for state tax purposes, it would substantially reduce the amount of cash available for distribution to Unitholders.

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

Despite the fact that we are a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. If we are so treated, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%, and we would likely pay additional state income taxes as well. Distributions to Unitholders would generally be taxed again as corporate distributions, and none of our income, gains, losses or deductions would flow through to Unitholders.

Because a tax would then be imposed upon us as a corporation, our cash available for distribution to Unitholders would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to the Unitholders, likely causing a substantial reduction in the value of our Common Units.

The present tax treatment of publicly traded partnerships, including us, or an investment in our Common Units, may be modified by administrative, legislative or judicial interpretation at any time, causing us to be treated as a corporation for federal income tax purposes or otherwise subjecting us to entity-level taxation. For example, recently, members of the U.S. Congress considered substantive changes to the existing U.S. federal income tax laws that would have affected the tax treatment of certain publicly traded partnerships. Several states currently impose entity-level taxes on partnerships, including us. Further, because of widespread state budget deficits and other reasons, several additional states are evaluating ways to subject partnerships to entity level taxation through the imposition of state income, franchise and other forms of taxation. If any additional states were to impose a tax upon us as an entity, our

cash available for distribution would be reduced. Any modification to the U.S. federal income or state tax laws, or interpretations thereof, may or may not be applied retroactively. Although we are unable to predict whether any of these changes

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or any other proposals will ultimately be enacted, any such changes could negatively impact the value of an investment in our Common Units.

Our Partnership Agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.

If the IRS contests the federal income tax positions we take, the market for our Common Units may be adversely affected and the costs of any such contest will reduce cash available for distributions to our Unitholders.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS may materially and adversely impact the market for our Common Units and the prices at which they trade. In addition, the costs of any contest with the IRS will be borne by us reducing the cash available for distribution to our Unitholders.

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

Because our Unitholders will be treated as partners to whom we will allocate taxable income which could be different in amount than the cash we distribute, Unitholders will be required to pay any federal income taxes and, in some cases, state and local income taxes on their share of our taxable income even if they receive no cash distributions from us. Unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from the taxation of their share of our taxable income.

Tax gain or loss on disposition of our Common Units could be more or less than expected.

If Unitholders sell their Common Units, they will recognize a gain or loss equal to the difference between the amount realized and the tax basis in those Common Units. Because distributions in excess of the Unitholder's allocable share of our net taxable income decrease the Unitholder's tax basis in their Common Units, the amount, if any, of such prior excess distributions with respect to the units sold will, in effect, become taxable income to the Unitholder if they sell such units at a price greater than their tax basis in those units, even if the price received is less than their original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a Unitholder's share of our nonrecourse liabilities, if a Unitholder sells units, the Unitholder may incur a tax liability in excess of the amount of cash received from the sale.

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

Investment in Common Units by tax-exempt entities, including employee benefit plans and individual retirement accounts (known as IRAs) and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to Unitholders who are organizations exempt from federal income tax, may be taxable to them as "unrelated business taxable income." Distributions to non-U.S. persons will be reduced by withholding taxes, generally at the highest applicable effective tax rate, and non-U.S. persons will be required to file United States federal and state income tax returns and generally pay United States federal and state income tax on their share of our taxable income. We treat each purchaser of Common Units as having the same tax benefits without regard to the actual Common Units purchased. The IRS may challenge this treatment, which could result in a Unitholder owing more tax and may adversely affect the value of the Common Units.

The IRS may challenge the manner in which we calculate our Unitholder's basis adjustment under Section 743(b) of the Internal Revenue Code. If so, because neither we nor a Unitholder can identify the units to which this issue relates once the initial holder has traded them, the IRS may assert adjustments to all Unitholders selling units within the period under audit as if all Unitholders owned such units.

Any position we take that is inconsistent with applicable Treasury Regulations may have to be disclosed on our federal income tax return. This disclosure increases the likelihood that the IRS will challenge our positions and propose adjustments to some or all of our Unitholders.

A successful IRS challenge to this position or other positions we may take could adversely affect the amount of taxable income or loss allocated to our Unitholders. It also could affect the gain from a Unitholder's sale of Common Units and could have a

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negative impact on the value of the Common Units or result in audit adjustments to our Unitholders' tax returns without the benefit of additional deductions. Moreover, because one of our subsidiaries that is organized as a C corporation for federal income tax purposes owns units in us, a successful IRS challenge could result in this subsidiary having more tax liability than we anticipate and, therefore, reduce the cash available for distribution to our partnership and, in turn, to our Unitholders.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our Unitholders.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations. Recently, however, the Department of the Treasury and the IRS issued proposed Treasury Regulations that provide a safe harbor pursuant to which a publicly traded partnership may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders. Nonetheless, the proposed regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge our proration method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our Unitholders.

A Unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of those units. If so, the Unitholder would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition.

Because a Unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of the loaned units, the Unitholder may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller and the Unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those units may not be reportable by the Unitholder and any cash distributions received by the Unitholder as to those units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between us and our public Unitholders. The IRS may challenge this treatment, which could adversely affect the value of our Common Units.

When we issue additional units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to such assets to the capital accounts of our Unitholders and our General Partner. Although we may from time to time consult with professional appraisers regarding valuation matters, including the valuation of our assets, we make many of the fair market value estimates of our assets ourselves using a methodology based on the market value of our Common Units as a means to measure the fair market value of our assets. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain Unitholders and our General Partner, which may be unfavorable to such Unitholders. Moreover, under our current valuation methods, subsequent purchasers of our Common Units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between our General Partner and certain of our Unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our Unitholders. It also could affect the amount of gain on the sale of Common Units by our Unitholders and could have a negative impact on the value of our Common Units or result in audit adjustments to the tax returns of our Unitholders without the benefit of additional deductions.

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

We will be considered technically terminated for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same unit will be counted only once. Our technical termination would, among other things, result in the closing of our taxable year for all Unitholders which would require us to file two federal partnership tax returns for one fiscal year, and could result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a Unitholder reporting on a taxable year other than a calendar year, the closing of our taxable year may also result in more than



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twelve months of our taxable income or loss being includable in such Unitholder's taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes. We would be treated as a new partnership for tax purposes on the technical termination date, and would be required to make new tax elections and could be subject to penalties if we were unable to determine in a timely manner that a termination occurred.

Unitholders will likely be subject to state and local taxes and return filing requirements in states where they do not live as a result of investing in our Common Units.

In addition to federal income taxes, the Unitholders may be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if they do not live in any of those jurisdictions. Unitholders may be required to file state and local income tax returns and pay state and local income taxes in some or all of the jurisdictions. We currently own property or conduct business in more than 40 states, either directly or indirectly as a result of our investment in AmeriGas. Most of these states impose an income tax on individuals, corporations and other entities. As we make acquisitions or expand our business, we may control assets or conduct business in additional states that impose a personal or corporate income tax. Further, Unitholders may be subject to penalties for failure to comply with those requirements. It is the responsibility of each Unitholder to file all federal, state and local tax returns.

### Risks Related to the Proposed Citrus Acquisition

Our acquisition of the 50% interest in Citrus is subject to the satisfaction of certain conditions to closing, one of which is the completion of the merger of SUG and a subsidiary of ETE.

Our acquisition of the 50% interest in Citrus Corp. currently owned by SUG is subject to the satisfaction of certain conditions to closing, including the absence of a material adverse change to the business or results of operations of Citrus Corp. subsequent to January 1, 2012, the receipt of necessary governmental approvals and the completion of the merger of SUG and a wholly-owned subsidiary of ETE. The completion of the merger of SUG and the subsidiary of ETE is subject to the absence of a material adverse change to the business or results of operation of ETE and SUG, the receipt of necessary regulatory approvals and the satisfaction or waiver of other conditions specified in the SUG Merger Agreement. In the event those conditions to closing are not satisfied or waived, we would not complete the acquisition of the 50% interest in Citrus Corp. currently owned by SUG.

Any acquisition we complete, including the Citrus Acquisition, is subject to substantial risks that could adversely affect our financial condition and results of operations and reduce our ability to make distributions to Unitholders.

Any acquisition we complete, including the proposed Citrus Acquisition, involves potential risks, including, among other things:

- the validity of our assumptions about revenues, capital expenditures and operating costs of the acquired business or assets, as well as assumptions about achieving synergies with our existing businesses;
- a significant increase in our interest expense and financial leverage resulting from any additional debt incurred to finance the acquisition consideration, which could offset the expected accretion to our Unitholders from such acquisition and could be exacerbated by volatility in the credit or debt capital markets;
- a failure to realize anticipated benefits, such as increased distributable cash flow per unit, enhanced competitive position or new customer relationships;
- a decrease in our liquidity by using a significant portion of our available cash or borrowing capacity to finance the acquisition;
- difficulties operating in new geographic areas or new lines of business;
- the incurrence or assumption of unanticipated liabilities, losses or costs associated with the business or assets acquired for which we are not indemnified or for which the indemnity is inadequate;
- the inability to hire, train or retrain qualified personnel to manage and operate our growing business and assets, including any newly acquired business or assets;
- the diversion of management's attention from our existing business; and
- the incurrence of other significant charges, such as impairment of goodwill or other intangible assets, asset devaluation or restructuring charges.

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

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Also, our reviews of businesses or assets proposed to be acquired are inherently incomplete because it generally is not feasible to perform an in-depth review of businesses and assets involved in each acquisition given time constraints imposed by sellers. Even a detailed review of assets and businesses may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the assets or businesses to fully assess their deficiencies and potential. Inspections may not always be performed on every asset, and environmental problems are not necessarily observable even when an inspection is undertaken.

In connection with the proposed Citrus Acquisition, we incurred substantial additional indebtedness.

The Citrus Merger Agreement requires that we pay \$1.895 billion to ETE as cash consideration for the interest in Citrus. In January 2012, we issued \$2.0 billion of senior notes and we plan to use net proceeds from this issuance to fund this cash payment. The incurrence of this additional indebtedness increased our overall level of debt and adversely affected our ratios of total indebtedness to EBITDA and EBITDA to interest expense, both on a current basis and a pro forma basis taking into account our acquisition of the 50% interest in Citrus. If we do not consummate the acquisition of the 50% interest in Citrus on or before April 17, 2012, or the Citrus Merger Agreement is terminated on or before such date, we must redeem the \$2.0 billion of senior notes at a redemption price equal to 101% of the aggregate principal amount of the notes, plus accrued and unpaid interest.

Class action stockholder litigation could prevent or delay completion of the SUG Merger and/or the Citrus Acquisition, and a third party is seeking rescission of the Citrus Acquisition or damages in connection therewith. In connection with the SUG Merger, purported stockholders of SUG have filed several stockholder class action lawsuits against ETE, SUG, and the SUG Board of Directors in the District Courts of Harris County, Texas and in the Delaware Courts of Chancery. Among other remedies, the plaintiffs may seek to enjoin the SUG Merger. If a final settlement is not reached, or if a dismissal is not obtained, these lawsuits could prevent or delay completion of the SUG Merger, which in turn could prevent or delay the completion of the Citrus Acquisition.

On November 28, 2011, the W.J. Garrett Trust filed a lawsuit in the 234th District Court of Harris County, Texas derivatively on behalf of ETP unitholders challenging the Citrus Acquisition and the contribution of our Propane Business to AmeriGas. The suit names ETP, ETE, SUG and the directors of both ETP and ETE as defendants. Specifically, the plaintiff alleges that the Citrus Acquisition and the contribution of the Propane Business to AmeriGas involved an unfair price and alleges deficiencies in the process by which the named directors and officers conducted those transactions. Additionally, the plaintiff alleges that (i) the named directors and officers breached their fiduciary and contractual duties in connection with the transactions; (ii) the named entities aided and abetted these breaches of the directors' and officers' fiduciary and contractual duties; (iii) SUG and ETE tortiously interfered with ETP's partnership agreement; and (iv) the defendants conspired to breach their fiduciary and contractual duties. On January 30, 2012, the defendants filed a motion challenging the sufficiency of the plaintiff's claim. A hearing on the defendants' motion is set for March 5, 2012 and trial is set for January 14, 2013. At this time, we are unable to predict the likelihood of an unfavorable outcome or any estimate of potential loss with respect to this matter.

CrossCountry, the SUG subsidiary directly holding the 50% interest in Citrus Corp., filed a petition in the Delaware Court of Chancery seeking a declaratory judgment against El Paso, the owner of the other 50% interest of Citrus Corp. This petition was filed by CrossCountry following an exchange of letters between CrossCountry, El Paso and Southern Union in which El Paso stated that it believed the Citrus Acquisition violated the provisions of the Capital Stock Agreement of Citrus Corp., dated June 30, 1986. Specifically, while not seeking an injunction of the merger, El Paso claims that the Citrus Acquisition violates El Paso's right of first refusal and seeks rescission of the Citrus Acquisition or, alternatively, damages. If El Paso is ultimately successful in asserting its position with respect to the terms of the Capital Stock Agreement, we cannot predict whether the court would determine that rescission would be an appropriate remedy or would otherwise award damages to El Paso and, if so, the amount of any such damages. Additional lawsuits may be filed against ETE and/or SUG related to the SUG Merger or against ETP and/or ETE related to the Citrus Acquisition.

**ITEM 1B. UNRESOLVED STAFF COMMENTS**

None.

ITEM 2. PROPERTIES

A description of our properties is included in “Item 1. Business.” We own an office building for our executive office in Dallas, Texas and office buildings in Houston and San Antonio, Texas. While we may require additional office space as our business expands, we believe that our existing facilities are adequate to meet our needs for the immediate future, and that additional facilities will be available on commercially reasonable terms as needed.

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

Substantially all of our pipelines, which are described in “Item 1. Business” are constructed on rights-of-way granted by the apparent record owners of the property. Lands over which pipeline rights-of-way have been obtained may be subject to prior liens that have not been subordinated to the right-of-way grants. We have obtained, where necessary, easement agreements from public authorities and railroad companies to cross over or under, or to lay facilities in or along, watercourses, county roads, municipal streets, railroad properties and state highways, as applicable. In some cases, properties on which our pipelines were built were purchased in fee. We also own and operate multiple natural gas and NGL storage facilities and own or lease other processing, treating and conditioning facilities in connection with our midstream operations.

**ITEM 3. LEGAL PROCEEDINGS**

We are not aware of any material legal or governmental proceedings against us or our Operating Companies, or contemplated to be brought against us or our Operating Companies, under the various environmental protection statutes to which we and they are subject.

For a description of legal proceedings, see Note 8 to our consolidated financial statements.

**ITEM 4. MINE SAFETY DISCLOSURES**

Not applicable.

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## PART II

## ITEM 5. MARKET FOR REGISTRANT'S COMMON UNITS, RELATED UNITHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

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

Our Common Units are listed on the New York Stock Exchange (the "NYSE") 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 NYSE Composite Tape, and the amount of cash distributions paid per Common Unit for the periods indicated.

	Price Range		Cash Distribution (1)
	High	Low	
Fiscal Year 2011			
Fourth Quarter	\$47.69	\$38.08	\$0.89375
Third Quarter	49.50	40.25	0.89375
Second Quarter	55.20	44.75	0.89375
First Quarter	55.50	50.31	0.89375
Fiscal Year 2010			
Fourth Quarter	\$52.00	\$48.01	\$0.89375
Third Quarter	51.95	44.97	0.89375
Second Quarter	49.99	40.06	0.89375
First Quarter	47.76	42.69	0.89375

Distributions are shown in the quarter with respect to which they relate. 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 (1) our Common Units outstanding at such time. Please see "— Cash Distribution Policy" below for a discussion of our policy regarding the payment of distributions.

## Description of Units

As of February 15, 2012, there were approximately 330,000 individual Common Unitholders, which includes Common Units held in street name. The Common Units are entitled to distributions of Available Cash as described below under "— Cash Distribution Policy."

In conjunction with our purchase of the capital stock of Heritage Holdings, Inc. ("HHI") in January 2004, there are currently 8,853,832 Class E Units outstanding, all of which are owned by HHI, our wholly-owned subsidiary. The Class E Units generally do not have any voting rights. These Class E Units are entitled to aggregate cash distributions equal to 11.1% of the total amount of cash distributed to all Unitholders, including the Class E Unitholders, up to \$1.41 per unit per year. As the Class E Units are owned by a wholly owned subsidiary, the cash distributions on those units are eliminated in our consolidated financial statements. Although no plans are currently in place, management may evaluate whether to retire the Class E Units at a future date.

As of December 31, 2011, our General Partner owned an approximate 1.5% general partner interest in us and the holders of Common Units and Class E Units collectively owned a 98.5% limited partner interest in us.

Incentive Distribution Rights ("IDRs") represent the contractual right to receive a specified percentage of quarterly distributions of Available Cash from operating surplus after the minimum quarterly distribution has been paid. Please read "— Distributions of Available Cash from Operating Surplus" below.

## 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.

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**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 and/or 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 used solely for working capital purposes or to pay distributions to partners. Available Cash is more fully defined in our Partnership Agreement, which is an exhibit to this report.

### **Operating Surplus and Capital Surplus**

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

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

• our cash balance on the closing date of our initial public offering in 1996; plus

• \$10.0 million (as described below); plus

• all of our cash receipts since the closing of our initial public offering, excluding cash from interim capital transactions such as borrowings that are not working capital borrowings, sales of equity and debt securities and sales or other dispositions of assets outside the ordinary course of business; plus

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

• all of our operating expenditures after the closing of our initial public offering, including the repayment of working capital borrowings, but not the repayment of other borrowings, and including maintenance capital expenditures; less the amount of our cash reserves that our General Partner deems necessary or advisable to provide funds for future operating expenditures.

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

• borrowings other than working capital borrowings;

• sales of our debt and equity securities;

• and

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

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

• First, 100% to all Common and Class E Unitholders and the General Partner, in accordance with their percentage interests, until each Common Unit has received \$0.25 per unit for such quarter (the “minimum quarterly distribution”);





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Second, 100% to all Common and Class E Unitholders and the General Partner, in accordance with their percentage interests, until each Common Unit has received \$0.275 per unit for such quarter (the “first target cash distribution”); Third, 87% to all Common and Class E Unitholders and the General Partner, in accordance with their percentage interests, and 13% to the holders of Incentive Distribution Rights, pro rata, until each Common Unit has received at least \$0.3175 per unit for such quarter (the “second target cash distribution”);

Fourth, 77% to all Common and Class E Unitholders and the General Partner, in accordance with their percentage interests, and 23% to the holders of Incentive Distribution Rights, pro rata, until each Common Unit has received at least \$0.4125 per unit for such quarter (the “third target cash distribution”); and

Fifth, thereafter, 52% to all Common and Class E Unitholders and the General Partner, in accordance with their percentage interests, and 48% to the holders of Incentive Distribution Rights, pro rata.

The allocation of distributions among the Common and Class E Unitholders and the General Partner is based on their respective interests as of the record date for such distributions.

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

**Distributions of Available Cash from Capital Surplus**

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

First, to all of our Unitholders and to our General Partner, in accordance with their percentage interests, until we distribute for each Common Unit, an amount of available cash from capital surplus equal to our initial public offering price; and

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

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

If we combine our units into fewer units or subdivide our units into a greater number of units, we will proportionately adjust our minimum quarterly distribution; our target cash distribution levels; and our unrecovered capital. For example, if a two-for-one split of our Common Units should occur, our unrecovered capital would be reduced to 50% of the initial level. We will not make any adjustment by reason of our issuance of additional units for cash or property. In addition, if legislation is enacted or if existing law is modified or interpreted in a manner that causes us to become taxable as a corporation or otherwise subject to additional taxation as an entity for federal, state or local income tax purposes, under the terms of the Partnership Agreement, we can reduce our minimum quarterly distribution and the target cash distribution levels by multiplying the same by one minus the sum of the highest marginal federal corporate income tax rate that could apply and any increase in the effective overall state and local income tax rates.

The total amount of distributions declared is reflected in Note 6 to our consolidated financial statements. All distributions were made from Available Cash from our operating surplus.

**Recent Sales of Unregistered Securities**

None.

**Issuer Purchases of Equity Securities**

None.

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## ITEM 6. SELECTED FINANCIAL DATA

In November 2007, we changed our fiscal year end from August 31 to December 31 and, in connection with such change, we have reported financial results for a four-month transition period ended December 31, 2007.

The selected financial data should be read in conjunction with “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” and the historical consolidated financial statements and the accompanying notes thereto included elsewhere in this report. The amounts in the table below, except per unit data, are in thousands.

	Years Ended December 31,				Four Months Ended December 31, 2007	Year Ended August 31, 2007
	2011	2010	2009	2008		
Statement of Operations Data:						
Total revenues	\$6,850,440	\$5,884,827	\$5,417,295	\$9,293,868	\$2,349,510	\$6,792,037
Operating income	1,244,807	1,058,171	1,127,607	1,117,579	323,634	829,652
Income from continuing operations	697,162	617,222	791,542	866,023	261,824	677,281
Basic net income per limited partner unit	1.10	1.20	2.53	3.74	1.24	3.32
Diluted net income per limited partner unit	1.10	1.19	2.53	3.74	1.24	3.31
Cash distributions per unit	3.58	3.58	3.58	3.55	1.13	3.19
Balance Sheet Data (at period end):						
Total assets	15,518,616	12,149,992	11,734,972	10,627,489	9,008,161	7,708,428
Long-term debt, less current maturities	7,388,170	6,404,916	6,176,918	5,618,549	4,297,264	3,626,977
Total equity	6,350,424	4,743,437	4,599,708	3,743,069	3,379,191	3,042,072
Other Financial Data:						
Capital expenditures:						
Maintenance (accrual basis)	134,164	99,275	102,652	140,968	48,998	89,226
Growth (accrual basis)	1,375,523	1,288,863	530,333	1,921,679	604,371	998,075
Cash (received in) paid for acquisitions	1,971,581	177,920	(30,367 )	84,783	337,092	90,695

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

The following is a discussion of our historical consolidated financial condition and results of operations, and should be read in conjunction with our historical consolidated financial statements and accompanying notes thereto included in "Item 8. Financial Statements and Supplementary Data" of this report. This discussion includes forward-looking statements that are subject to risk and uncertainties. Actual results may differ substantially from the statements we make in this section due to a number of factors that are discussed in "Item 1A. Risk Factors" included in this report. References to "we," "us," "our", the "Partnership" and "ETP" shall mean Energy Transfer Partners, L.P. and its subsidiaries.

Overview

The activities and the wholly-owned operating subsidiaries through which we conduct those activities are as follows:

• Natural gas operations, including the following segments:

• natural gas midstream and intrastate transportation and storage through La Grange Acquisition, L.P., which conducts business under the assumed name of Energy Transfer Company ("ETC OLP"); and interstate natural gas transportation services through Energy Transfer Interstate Holdings, LLC ("ET Interstate"). ET Interstate is the parent company of Transwestern Pipeline Company, LLC ("Transwestern"), ETC Fayetteville Express Pipeline, LLC ("ETC FEP") and ETC Tiger Pipeline, LLC ("ETC Tiger").

• NGL transportation, storage and fractionation services primarily through Lone Star NGL LLC ("Lone Star").

• Retail propane through Heritage Operating, L.P. ("HOLP") and Titan Energy Partners, L.P. ("Titan").

• Other operations, including natural gas compression services.

Recent Developments

Propane Operations

On January 12, 2012 we contributed our propane operations, consisting of HOLP and Titan (collectively, the "Propane Business"), to AmeriGas Partners, L.P. ("AmeriGas"). We received approximately \$1.46 billion in cash and 29.6 million AmeriGas common units. AmeriGas also assumed approximately \$71 million of existing HOLP debt.

Citrus Acquisition

On July 19, 2011, we entered into the Amended Citrus Merger Agreement pursuant to which it is anticipated that Southern Union Company, a Delaware corporation ("SUG"), will cause the contribution to us of a 50% interest in Citrus Corp., which owns 100% of the Florida Gas Transmission ("FGT") pipeline system, in exchange for approximately \$1.895 billion in cash and \$105 million of our Common Units, contemporaneous with the completion of the merger between SUG and ETE pursuant to the SUG Merger Agreement.

Expansion of Rich Eagle Ford Mainline

In February 2012, we announced our entry into multiple long-term, fee-based agreements with producers to provide natural gas gathering, processing, and liquids services from the Eagle Ford Shale in south Texas. To facilitate the agreements, we will further expand the REM pipeline and construct a new processing facility at an expected cost of \$210 million. The pipeline expansion announced in February 2012 is expected to be completed in the fourth quarter of 2013, and the processing facility announced in February 2012 is expected to be completed in the fourth quarter of 2012.

Construction of Second Fractionator at Lone Star's Mont Belvieu Fractionation Facility

In February 2012, Lone Star announced the construction of a second 100,000 Bbls/d fractionation facility at Mont Belvieu, Texas. Supported by multiple long-term contracts, the second fractionator is necessary to handle the increasing NGL barrels delivered via the partnership's Woodford Shale, Eagle Ford Shale and Permian Basin infrastructure, including Lone Star's 570-mile West Texas Gateway NGL Pipeline. This second fractionation facility is expected to be completed in the first quarter of 2014 at an estimated cost of \$350 million.

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2012 Financing Transactions

In January 2012, we issued \$2.0 billion principal amount of Senior Notes, the proceeds from which we anticipate using to fund the cash portion of the Citrus Acquisition and for general partnership purposes. In January and February 2012, we also completed the repurchase of approximately \$750 million of our Senior Notes.

General

Our primary objective is to increase the level of our distributable cash flow over time by pursuing a business strategy that is currently focused on growing our natural gas and NGL businesses through, among other things, pursuing certain construction and expansion opportunities relating to our existing infrastructure and acquiring certain strategic operations and businesses or assets as demonstrated by our acquisition with Regency of LDH Energy Asset Holdings LLC (“LDH”), our pending Citrus Acquisition and our recent announcements regarding organic growth projects. The actual amounts of cash that we will have available for distribution will primarily depend on the amount of cash we generate from our operations.

During the past several years, we have been successful in completing several transactions that have increased our distributable cash flow. We have also made, and are continuing to make, significant investments in internal growth projects, primarily the construction of pipelines, gathering systems and natural gas treating and processing plants, which we believe will provide additional cash available for distributions to our Partnership for years to come.

Our principal operations as of December 31, 2011 included the following segments:

Intrastate natural gas transportation and storage – Revenue is principally generated from fees charged to customers to reserve firm capacity on or move gas through our pipelines on an interruptible basis. Our interruptible or short-term business is generally impacted by basis differentials between delivery points on our system and the price of natural gas. The basis differentials that primarily impact our interruptible business are primarily among receipt points between West Texas to East Texas or segments thereof. When narrow or flat spreads exist, our open capacity may be underutilized and go unsold. Conversely, when basis differentials widen, our interruptible volumes and fees generally increase. The fee structure normally consists of a monetary fee and fuel retention. Excess fuel retained after consumption, if any, is typically sold at market prices. In addition to transport fees, we generate revenue from purchasing natural gas and transporting it across our system. The natural gas is then sold to electric utilities, independent power plants, local distribution companies, industrial end-users and other marketing companies. The HPL System purchases natural gas at the wellhead for transport and selling. Other pipelines with access to West Texas supply, such as Oasis and ET Fuel, may also purchase gas at the wellhead and other supply sources for transport across our system to be sold at market on the east side of our system. This activity allows our intrastate transportation and storage segment to capture the current basis differentials between delivery points on our system or to capture basis differentials that were previously locked in through hedges. Firm capacity long-term contracts are typically not subject to price differentials between shipping locations.

We also generate fee-based revenue from our natural gas storage facilities by contracting with third parties for their use of our storage capacity. From time to time, we inject and hold natural gas in our Bammel storage facility to take advantage of contango markets, a term used to describe a pricing environment when the price of natural gas is higher in the future than the current spot price. We use financial derivatives to hedge the natural gas held in connection with these arbitrage opportunities. Our earnings from natural gas storage we purchase, store and sell are subject to the current market prices (spot price in relation to forward price) at the time the storage gas is hedged. At the inception of the hedge, we lock in a margin by purchasing gas in the spot market and entering into a financial derivative to lock in the forward sale price. If we designate the related financial derivative as a fair value hedge for accounting purposes, we value the hedged natural gas inventory at current spot market prices whereas the financial derivative is valued using forward natural gas prices. As a result of fair value hedge accounting, we have elected to exclude the spot forward premium from the measurement of effectiveness and changes in the spread between forward natural gas prices and spot market prices result in unrealized gains or losses until the underlying physical gas is withdrawn and the related financial derivatives are settled. Once the gas is withdrawn and the designated derivatives are settled, the previously unrealized gains or losses associated with these positions are realized. If the spread narrows between spot and forward prices, we will record unrealized gains or lower unrealized losses. If the spread widens prior to withdrawal of the gas, we will record unrealized losses or lower unrealized gains.

As noted above, any excess retained fuel is sold at market prices. To mitigate commodity price exposure, we will use financial derivatives to hedge prices on a portion of natural gas volumes retained. For certain contracts that qualify for hedge accounting, we designate them as cash flow hedges of the forecasted sale of gas. The change in value, to the extent the contracts are effective, remains in accumulated other comprehensive income until the forecasted transaction occurs. When the forecasted transaction occurs, any gain or loss associated with the derivative is recorded in cost of products sold in the consolidated statement of operations.

In addition, we use financial derivatives to lock in price differentials between market hubs connected to our assets on a portion of our intrastate transportation system's unreserved capacity. Gains and losses on these financial derivatives are dependent

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on price differentials at market locations, primarily points in West Texas and East Texas. We account for these derivatives using mark-to-market accounting, and the change in the value of these derivatives is recorded in earnings. During the fourth quarter of 2011, we began using derivatives for trading purposes.

Interstate natural gas transportation – The majority of our interstate transportation revenues are generated through firm reservation charges that are based on the amount of firm capacity reserved for our firm shippers regardless of usage. Tiger, Fayetteville Express Pipeline LLC (“FEP”) and Transwestern expansion shippers have made 10- to 15-year commitments to pay reservation charges for the firm capacity reserved for their use. In addition to reservation revenues, additional revenue sources include interruptible transportation charges as well as usage rates and overrun rates paid by firm shippers based on their actual capacity usage.

Midstream – Revenue is principally dependent upon the volumes of natural gas gathered, compressed, treated, processed, purchased and sold through our pipelines as well as the level of natural gas and NGL prices.

In addition to fee-based contracts for gathering, treating and processing, we also have percent-of-proceeds and keep-whole contracts, which are subject to market pricing. For percent-of-proceeds contracts, we retain a portion of the natural gas and NGLs processed, or a portion of the proceeds of the sales of those commodities, as a fee. When natural gas and NGL prices increase, the value of the portion we retain as a fee increases. Conversely, when prices of natural gas and NGLs decrease, so does the value of the portion we retain as a fee. For wellhead (keep-whole) contracts, we retain the difference between the price of NGLs and the cost of the gas to process the NGLs. In periods of high NGL prices relative to natural gas, our margins increase. During periods of low NGL prices relative to natural gas, our margins decrease or could become negative; however, we have the ability to bypass our processing plants to avoid negative margins that may occur from processing NGLs in the event it is uneconomical to process this gas. Our processing contracts and wellhead purchases in rich natural gas areas provide that we earn and take title to specified volumes of NGLs, which we also refer to as equity NGLs. Equity NGLs in our midstream segment are derived from performing a service in a percent-of-proceeds contract or produced under a keep-whole arrangement.

In addition to NGL price risk, our processing activity is also subject to price risk from natural gas because, in order to process the gas, in some cases we must purchase it. Therefore, lower gas prices generally result in higher processing margins.

We conduct marketing operations in which we market certain of the natural gas that flows through our assets, referred to as on-system gas. We also attract other customers by marketing volumes of natural gas that does not originate from our assets, referred to as off-system gas. For both on-system and off-system gas, we purchase natural gas from natural gas producers and other suppliers 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 of natural gas, less the costs of transportation.

NGL transportation and services – NGL transportation revenue is principally generated from fees charged to customers under dedicated contracts or take-or-pay contracts. Under a dedicated contract, the customer agrees to deliver the total output from particular processing plants that are connected to the NGL pipeline. Take-or-pay contracts have minimum throughput commitments requiring the customer to pay regardless of whether a fixed volume is transported.

Transportation fees are market-based, negotiated with customers and competitive with regional regulated pipelines. NGL storage revenues are derived from base storage fees and throughput fees. Base storage fees are based on the volume of capacity reserved, regardless of the capacity actually used. Throughput fees are charged for providing ancillary services, including receipt and delivery, custody transfer, rail/truck loading and unloading fees. Storage contracts may be for dedicated storage or fungible storage. Dedicated storage enables a customer to reserve an entire storage cavern, which allows the customer to inject and withdraw proprietary and often unique products. Fungible storage allows a customer to store specified quantities of NGL products that are commingled in a storage cavern with other customers’ products of the same type and grade. NGL storage contracts may be entered into on a firm or interruptible basis. Under a firm basis contract, the customer obtains the right to store products in the storage caverns throughout the term of the contract; whereas, under an interruptible basis contract, the customer receives only limited assurance regarding the availability of capacity in the storage caverns.

This segment also includes revenues earned from processing and fractionating refinery off-gas. Under these contracts we receive an O-grade stream from cryogenic processing plants located at refineries and fractionate the products into

their pure components. We deliver purity products to customers through pipelines and across a truck rack located at the fractionation complex. In addition to revenues for fractionating the O-grade stream, we have percentage-of-proceeds and income sharing contracts, which are subject to market pricing of olefins and NGLs. For percentage-of-proceeds contracts, we retain a portion of the purity NGLs and olefins processed, or a portion of the proceeds from the sales of those commodities, as a fee. When NGLs and olefin prices increase, the value of the portion we retain as a fee increases. Conversely, when NGLs and olefin prices decrease, so does the value of the portion we retain as a fee. Under our income sharing contracts, we pay the producer the equivalent energy value for their liquids, similar to a traditional keep-whole processing agreement, and then share in the residual income created by the difference between NGLs and olefin prices as compared to natural gas prices. As NGLs and

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olefins prices increase in relation to natural gas prices, the value of the percent we retain as a fee increases. Conversely, when NGLs and olefins prices decrease as compared to natural gas prices, so does the value of the percent we retain as a fee.

Retail propane and other retail propane related operations – Revenue is principally generated from the sale of propane and propane-related products and services. The retail propane segment is a margin-based business in which gross profits depend on the excess of sales price over propane supply cost. Consequently, the profitability of our retail propane business is sensitive to changes in wholesale propane prices. Our propane business is largely seasonal and dependent upon weather conditions in our service areas. We use information published by the National Oceanic and Atmospheric Administration (“NOAA”) to gather heating degree day data to analyze how our sales volumes may be affected by temperature. Our normal temperatures are defined as the prior ten year weighted-average temperature which is based on the average heating degree days provided by NOAA gathered from the various measuring points in our operating areas weighted by the retail volumes attributable to each measuring point.

### Trends and Outlook

We intend to continue to maintain sufficient liquidity to allow us to fund growth projects and acquisitions as such new projects and acquisitions are identified in the future. To that end, we have secured financing for the Citrus Acquisition, which we expect to consummate in the near term, by issuing \$2.0 billion of senior notes in January 2012. We also completed the contribution of our Propane Business in January 2012, which not only improved our liquidity, but also allows us to focus on our core businesses in the natural gas and NGL markets. The completion of the LDH Acquisition in 2011 marked our entry into NGL transportation and related services, which expands our business mix that had previously been predominantly focused on natural gas. We expect to continue development of the NGL business in order to take advantage of the currently strong environment.

With respect to industry trends, we expect to see continued high natural gas storage levels and continued growth in natural gas supply. Much of the growth in supply is due to the continued discovery and development of new natural gas shale formations as well as natural gas associated with wells targeting liquids production. We expect overall consumption of natural gas in the United States to be stable during 2012. In our natural gas operations, a significant portion of our revenue continues to be derived from long-term fee-based arrangements, pursuant to which our customers pay us capacity reservation fees regardless of the volume of natural gas transported; however, we do recognize a portion of our revenue from fees based on volumes transported. We expect these volumes to be relatively consistent with 2011 with a downward trend in areas where we have assets connected to dry gas given the outlook on natural gas prices and production in 2012.

We continue to evaluate and execute strategies to mitigate the effects of changing prices. These strategies include hedging net retained fuel volumes. As of January 31, 2012, all of our estimated 2012 and 2013 net retained fuel volumes were hedged. We also benefit from price differentials between receipt and delivery points on our system. These differentials are a driver of volumes from certain of our customers and we also can capture price differentials on our open capacity. We do not expect a significant change in price differentials between locations our assets are connected to during 2012 based on current supply, demand and capacity dynamics.

With our expansion of activities in the Eagle Ford Shale and Permian Basin, we expect growth in margin from our midstream segment as we continue to meet our customers' needs in these rich natural gas shale formations. We also anticipate NGL prices to be stable during 2012 given strong underlying fundamentals.

### Results of Operations

We previously reported segment operating income as a measure of segment performance. We have revised certain reports provided to our chief operating decision maker to assess the performance of our business to reflect Segment Adjusted EBITDA. Segment Adjusted EBITDA reflects amounts for less than wholly owned subsidiaries and unconsolidated affiliates based on the Partnership's proportionate ownership. Based on the change in our segment performance measure, we have recast the presentation of our segment results for the prior years to be consistent with the current year presentation.

When presented on a consolidated basis, Adjusted EBITDA is a non-GAAP measure. Although we include Segment Adjusted EBITDA in this report, we have not included an analysis of the consolidated measure, Adjusted EBITDA.



We have included a total of Segment Adjusted EBITDA for all segments, which is reconciled to the GAAP measure of net income in the consolidated results sections that follow.

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Year Ended December 31, 2011 Compared to the Year Ended December 31, 2010 (tabular dollar amounts are expressed in thousands)

## Consolidated Results

	Years ended December 31,		
	2011	2010	Change
Segment Adjusted EBITDA			
Intrastate transportation and storage	\$667,294	\$716,176	\$(48,882 )
Interstate transportation	373,409	220,027	153,382
Midstream	388,578	329,025	59,553
NGL transportation and services	88,197	—	88,197
Retail propane and other retail propane related	222,204	269,670	(47,466 )
All other	2,881	5,990	(3,109 )
Total Segment Adjusted EBITDA	1,742,563	1,540,888	201,675
Depreciation and amortization	(430,904 )	(343,011 )	(87,893 )
Interest expense, net of interest capitalized	(474,113 )	(412,553 )	(61,560 )
Gains (losses) on non-hedged interest rate derivatives	(77,409 )	4,616	(82,025 )
Income tax expense	(18,815 )	(15,536 )	(3,279 )
Non-cash compensation expense	(37,457 )	(27,180 )	(10,277 )
Allowance for equity funds used during construction	957	28,942	(27,985 )
Unrealized losses on commodity risk management activities	(11,407 )	(78,300 )	66,893
Impairment of investments in affiliates	(5,355 )	(52,620 )	47,265
Losses on disposal of assets	(3,188 )	(5,043 )	1,855
Adjusted EBITDA attributable to noncontrolling interest	37,842	—	37,842
Proportionate share of unconsolidated affiliates' interest, depreciation and allowance for equity funds used during construction	(29,994 )	(22,499 )	(7,495 )
Other, net	4,442	(482 )	4,924
Net income	\$697,162	\$617,222	\$79,940

See the detailed discussion of Segment Adjusted EBITDA below.

**Depreciation and Amortization.** Depreciation and amortization increased due to acquisitions and assets placed in service since 2010. Depreciation and amortization increased by \$28.3 million for our interstate transportation segment primarily due to the Tiger pipeline which was placed in service in December 2010. Depreciation and amortization increased by \$25.3 million for midstream segment primarily due to incremental depreciation from the continued expansion of our Louisiana and South Texas assets. Depreciation and amortization for our NGL transportation and services segment was \$32.5 million from its inception in May 2011 through December 31, 2011.

**Interest Expense.** Interest expense increased primarily due to the issuance of \$1.5 billion of senior notes in May 2011, the proceeds from which were used to repay borrowings on our revolving credit facility, to fund growth projects and for general partnership purposes. Interest expense was presented net of capitalized interest and allowance for debt funds used during construction, which totaled \$12.8 million and \$16.3 million during 2011 and 2010, respectively.

**Gains (Losses) on Non-Hedged Interest Rate Derivatives.** The year ended December 31, 2011 reflected losses on non-hedged interest rate swaps for which we had total notional amounts outstanding of \$1.65 billion as of December 31, 2011, which included \$1.15 billion of forward-starting floating-to-fixed swaps used to hedge interest rates associated with anticipated note issuances and \$500 million of fixed-to-floating swaps used to swap a portion of our fixed rate debt to floating. During the second half of 2011, forward rates decreased significantly due to global economic uncertainty which resulted in unrealized non-cash losses on our forward-starting floating-to-fixed swaps.

**Income Tax Expense.** The increase in income tax expense between the periods was primarily due to increases in taxable income within our subsidiaries that are taxable corporations, in addition to an increase in amounts recorded for the Texas margins tax resulting from increased operating income.



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Non-Cash Compensation Expense. The increase in non-cash compensation expense was due to an increase in the number of restricted unit awards granted.

Allowance for Equity Funds Used During Construction. Allowance for equity funds used during construction for 2011 reflected amounts recorded in connection with the expansion of the Tiger pipeline, which was completed in August 2011, whereas 2010 reflected amounts recorded in connection with the original construction of the Tiger pipeline.

Unrealized Losses on Commodity Risk Management Activities. See discussion of the unrealized loss on commodity risk management activities included in the discussion of segment results below.

Impairment of Investments in Affiliates. For 2011, our results reflected a non-cash charge to write off all of our investment in a joint venture for which projects are no longer being pursued. During 2010, in conjunction with the transfer of our interest in Midcontinent Express Pipeline on May 26, 2010, we recorded a non-cash charge of approximately \$52.6 million to reduce the carrying value of our interest to its estimated fair value.

Adjusted EBITDA Attributable to Noncontrolling Interest. The amount reflected for 2011 represents the proportionate share of Lone Star's Adjusted EBITDA attributable to Regency's 30% interest in Lone Star. This amount was excluded from the measure of Segment Adjusted EBITDA. Net income includes the results attributable to Lone Star on a consolidated basis.

Proportionate Share of Unconsolidated Affiliates' Interest, Depreciation and Allowance for Equity Funds Used During Construction. Amounts reflected for 2011 and 2010 primarily represent our proportionate share of such amounts for FEP for both periods and Midcontinent Express Pipeline LLC ("MEP") for 2010. Such amounts were included in calculating Segment Adjusted EBITDA and net income.

Segment Operating Results

Our reportable segments are discussed below. "All other" includes our compression and wholesale propane businesses. We evaluate segment performance based on Segment Adjusted EBITDA, which we believe is an important performance measure of the core profitability of our operations. This measure represents the basis of our internal financial reporting and is one of the performance measures used by senior management in deciding how to allocate capital resources among business segments.

The tables below identify the components of Segment Adjusted EBITDA, which is calculated as follows:

Gross margin, operating expenses, and selling, general and administrative. These line items are the amounts included in our consolidated financial statements that are attributable to each segment.

Unrealized gains or losses on commodity risk management activities. These are the unrealized amounts that are included in cost of products sold to calculate gross margin. These amounts are not included in Segment Adjusted EBITDA; therefore, the unrealized losses are added back and the unrealized gains are subtracted to calculate the segment measure.

Non-cash compensation expense. These amounts represent the total non-cash compensation recorded in operating expenses and selling, general and administrative. This expense is not included in Segment Adjusted EBITDA and therefore is added back to calculate the segment measure.

Adjusted EBITDA related to unconsolidated affiliates. These amounts represent our proportionate share of the Adjusted EBITDA of our unconsolidated affiliates. Amounts reflected are calculated consistently with our definition of Adjusted EBITDA above.

Adjusted EBITDA attributable to noncontrolling interest. These amounts represent the portion of Segment Adjusted EBITDA attributable to noncontrolling interest. Currently, the only noncontrolling interest in ETP is the 30% interest in Lone Star that is held by Regency. We reflect this amount as noncontrolling interest because we consolidate 100% of Lone Star on our consolidated financial statements.

For additional information regarding our business segments, see “Item 1. Business” and Notes 1 and 12 to our consolidated financial statements. In addition, following the acquisition of all of the membership interests in LDH on May 2, 2011, we have added an NGL transportation and services segment, which includes all of Lone Star’s results of operations.

**Selling, General and Administrative Expenses Not Allocated to Segments.** Selling, general and administrative expenses are allocated monthly to the Operating Companies using the Modified Massachusetts Formula Calculation (“MMFC”). The expenses subject to allocation are based on estimated amounts and take into consideration our actual expenses from previous months and

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known trends. The difference between the allocation and actual costs is adjusted in the following month which results in over or under allocation of these costs due to timing differences.

## Intrastate Transportation and Storage

	Years Ended December 31,		
	2011	2010	Change
Natural gas MMBtu/d — transported	11,295,084	12,251,457	(956,373 )
Revenues	\$2,674,157	\$3,290,905	\$(616,748 )
Cost of products sold	1,774,006	2,381,397	(607,391 )
Gross margin	900,151	909,508	(9,357 )
Unrealized losses on commodity risk management activities	9,994	62,370	(52,376 )
Operating expenses, excluding non-cash compensation expense	(191,488 )	(194,955 )	3,467
Selling, general and administrative, excluding non-cash compensation expense	(53,982 )	(63,454 )	9,472
Adjusted EBITDA related to unconsolidated affiliates	2,619	2,707	(88 )
Segment Adjusted EBITDA	\$667,294	\$716,176	\$(48,882 )

Volumes. Transported volumes decreased due to a less favorable natural gas price environment and lower basis differentials primarily between the West and East Texas market hubs offset by increased volumes from rich natural gas shale formations primarily in the Eagle Ford and certain areas of the Barnett Shale. The average spot price difference between these locations was \$0.036/MMBtu in 2011 compared to \$0.127/MMBtu in 2010.

Gross Margin. The components of our intrastate transportation and storage segment gross margin were as follows:

	Years Ended December 31,		
	2011	2010	Change
Transportation fees	\$599,380	\$594,405	\$4,975
Natural gas sales and other	107,007	110,002	(2,995 )
Retained fuel revenues	129,712	143,606	(13,894 )
Storage margin, including fees	64,052	61,495	2,557
Total gross margin	\$900,151	\$909,508	\$(9,357 )

In 2011, our gross margin decreased as compared to 2010 due to the net impact of the following factors:

• Additional demand-based contracts offset a decline in transported volumes, resulting in a net increase of \$5 million in transportation fees.

• From time to time, our marketing affiliate will contract with our intrastate pipelines for long-term and interruptible transportation capacity. Our intrastate transportation and storage segment recorded intercompany transportation fees from our marketing affiliate of \$35.7 million in 2011 compared to \$40.0 million in 2010. The decrease of \$4.2 million between periods was primarily due to a reduction in the amount of capacity utilized by our marketing affiliate.

• Margin from natural gas sales and other activity decreased \$3.0 million in 2011 as compared to 2010 primarily due to unfavorable impacts from system optimization activities.

The margin from the natural gas sales and other includes purchased natural gas for transport and sale, derivatives used to hedge transportation activities, and gains and losses on derivatives used to hedge net retained fuel. During the fourth quarter of 2011, our trading activities included the use of financial commodity derivatives. Excluding derivatives related to storage, unrealized losses of \$21.3 million were recorded in 2011 compared to unrealized losses of \$13.3 million in 2010.

Retained fuel revenues include gross volumes retained as a fee at the current market price; the cost of consumed fuel is included in operating expenses. Retention revenue decreased \$13.9 million due to less volumes and a decline in average natural gas spot prices, which averaged \$4.03/MMBtu in 2011 compared to an average of \$4.35/MMBtu in 2010.



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Storage margin was comprised of the following:

	Years Ended December 31,		Change
	2011	2010	
Withdrawals from storage natural gas inventory (MMBtu)	24,517,008	39,784,446	(15,267,438 )
Margin on physical sales	\$ 10,433	\$ 68,661	\$(58,228 )
Settlements of derivatives	8,332	1,517	6,815
Realized margin on natural gas inventory transactions	18,765	70,178	(51,413 )
Fair value inventory adjustments	(51,529 )	(57,157 )	5,628
Unrealized gains on derivatives	62,875	8,842	54,033
Margin recognized on natural gas inventory, including related derivatives	30,111	21,863	8,248
Revenues from fee-based storage	34,449	40,674	(6,225 )
Other costs	(508 )	(1,042 )	534
Total storage margin	\$ 64,052	\$ 61,495	\$ 2,557

The increase in our storage margin was principally driven by gains in derivatives offsetting a decline in the margin on physical sale due to a decrease in withdrawals of natural gas from our Bammel storage facility as a result of warmer than normal weather patterns. Additionally, we experienced a decline in fee-based storage revenue due to the cessation in 2011 of fixed fee contracts representing 4.5 Bcf of storage capacity.

**Unrealized Losses on Commodity Risk Management Activities.** Unrealized losses on commodity risk management activities reflect the net impact from unrealized gains and losses on storage and non-storage derivatives, as well as fair value adjustments on inventory. Unrealized losses decreased in 2011 compared to 2010 primarily due to the timing of storage withdrawals and declining forward prices. We also recorded additional mark-to-market losses of \$8.0 million in 2011 not related to storage.

**Operating Expenses, Excluding Non-Cash Compensation Expense.** Intrastate transportation and storage operating expenses decreased between the periods primarily due to a decrease in the cost of natural gas consumed of \$1.3 million due to lower gas prices and a decrease of \$6.6 million in operating and maintenance expense compared to 2010. These decreases were partially offset by higher ad valorem taxes of \$1.7 million due to expansions on our HPL system and increased employee costs of \$2.7 million.

**Selling, General and Administrative Expenses, Excluding Non-Cash Compensation Expense.** Intrastate transportation and storage selling, general and administrative expenses decreased between the periods primarily due to a decrease in allocated overhead expenses. A lower amount of overhead expenses were allocated to the intrastate transportation and storage segment in 2011 because of growth in other segments and the addition of NGL transportation and services segment.

Interstate Transportation

Years Ended December 31,  
2011