Energy Transfer Partners, L.P.
Form 10-K
March 01, 2013
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

ý ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2012

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 ý 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 ý

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 ý 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 ý 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 ý 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 ý

The aggregate market value as of June 29, 2012, 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 $7.89 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 26, 2013, the registrant had 303,651,548 Common Units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None

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Forward-Looking Statements

Certain matters discussed in this report, excluding historical information, as well as some statements by Energy Transfer Partners, L.P. (“ETP”, “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,” “cou “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, expected, 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
AmeriGas	AmeriGas Partners, L.P.
AOCI	accumulated other comprehensive income (loss)
AROs	asset retirement obligations
Bbls	barrels
Bcf	billion cubic feet
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 used
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
Citrus	Citrus Corp.
CrossCountry	CrossCountry Energy, LLC
DOT	U.S. Department of Transportation
Enterprise	Enterprise Products Partners L.P., together with its subsidiaries
ETC Compression	ETC Compression, LLC

ETC FEP	ETC Fayetteville Express Pipeline, LLC
ETC OLP	La Grange Acquisition, L.P., which conducts business under the assumed name of Energy Transfer Company
ETC Tiger	ETC Tiger Pipeline, LLC
ETE	Energy Transfer Equity, L.P., a publicly traded partnership and the owner of ETP LLC
ET Interstate	Energy Transfer Interstate Holdings, LLC

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ETP GP	Energy Transfer Partners GP, L.P., the general partner of ETP
ETP LLC	Energy Transfer Partners, L.L.C., the general partner of ETP GP
EPA	U.S. Environmental Protection Agency
Exchange Act	Securities Exchange Act of 1934
FEP	Fayetteville Express Pipeline LLC
FERC	Federal Energy Regulatory Commission
FGT	Florida Gas Transmission Company, LLC
GAAP	accounting principles generally accepted in the United States of America
Holdco	ETP Holdco Corporation
HOLP	Heritage Operating, L.P.
IDRs	incentive distribution rights
LDH	LDH Energy Asset Holdings LLC, a wholly-owned subsidiary of Louis Dreyfus Highbridge Energy LLC (subsequently renamed Castleton Commodities International, LLC)
LIBOR	London Interbank Offered Rate
LNG	Liquefied natural gas
Lone Star	Lone Star NGL LLC
LPG	liquefied petroleum gas
MMBtu	million British thermal units
MMcf	million cubic feet
NGL	natural gas liquid, such as propane, butane and natural gasoline
NYMEX	New York Mercantile Exchange
OTC	over-the-counter
OSHA	federal Occupational Safety and Health Act
Panhandle	Panhandle Eastern Pipe Line Company, LP
PCBs	polychlorinated biphenyls

PHMSA	Pipeline Hazardous Materials Safety Administration
Regency	Regency Energy Partners LP, a subsidiary of ETE
Reservoir	a porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is separate from other reservoirs
Sea Robin	Sea Robin Pipeline Company, LLC
SEC	Securities and Exchange Commission
Southern Union	Southern Union Company
Southwest Gas	Pan Gas Storage, LLC (d.b.a. Southwest Gas)
SUGS	Southern Union Gas Services

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Sunoco	Sunoco, Inc.
Sunoco Logistics	Sunoco Logistics Partners L.P.
Tcf	trillion cubic feet
Titan	Titan Energy Partners, L.P.
Transwestern	Transwestern Pipeline Company, LLC
Trunkline	Trunkline Gas Company, LLC

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, loss on extinguishment of debt, gain on deconsolidation 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 based on 100% of the subsidiaries' results of operations and for unconsolidated affiliates based on the Partnership's proportionate ownership.

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PART I

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 $14.19 billion as of January 31, 2013). 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 Southern Union and La Grange Acquisition, L.P., which conducts business under the assumed name of ETC OLP; and
  - interstate natural gas transportation and storage through ET Interstate and Southern Union. ET Interstate is the parent company of Transwestern, ETC FEP, ETC Tiger and CrossCountry. Southern Union is the parent company of Panhandle, which provides transportation and storage services through Panhandle, Trunkline and Sea Robin transmission systems.
- NGL transportation, storage and fractionation services primarily through Lone Star.
- Refined product and crude oil operations, including the following:
  - refined product and crude oil transportation through Sunoco Logistics; and
  - retail marketing of gasoline and middle distillates through Sunoco.
- Other operations, including the following:
  - natural gas compression services through ETC Compression;
  - a limited partner interest in AmeriGas;
  - natural gas distribution operations through Southern Union; and
  - an approximate 30% non-operating interest in a refining joint venture.

Previously we conducted our retail propane activities through HOLP and Titan. On January 12, 2012, we contributed HOLP and Titan to AmeriGas, as discussed in Note 4 of the consolidated financial statements included in Item 8.

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The following chart summarizes our organizational structure as of December 31, 2012:

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 2012 and Beyond

Strategic Transactions

Our significant strategic transactions in 2012 included the following, as discussed in more detail herein:

- 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 30 million AmeriGas common units. AmeriGas assumed approximately $71 million of existing HOLP debt. In connection with the closing of this transaction, we entered into a support agreement with AmeriGas pursuant to which we are obligated to provide contingent, residual support

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of $1.5 billion of intercompany indebtedness owed by AmeriGas to a finance subsidiary that in turn supports the repayment of $1.5 billion of senior notes issued by this AmeriGas finance subsidiary to finance the cash portion of the purchase price.

- In January 2012, we issued $2.0 billion of senior notes and used the proceeds fund the cash portion of our acquisition of a 50% interest in Citrus (the "Citrus Acquisition").
- On October 5, 2012, ETP completed its merger with Sunoco. Under the terms of the merger agreement, Sunoco shareholders received a total of approximately 55 million ETP Common Units and approximately $2.6 billion in cash (the "Sunoco merger").
- Immediately following the closing of the Sunoco merger, ETE contributed its interest in Southern Union into Holdco, an ETP-controlled entity, in exchange for a 60% equity interest in Holdco. In conjunction with ETE's contribution, ETP contributed its interest in Sunoco to Holdco and retained a 40% equity interest in Holdco. We refer to this as the "Holdco Transaction". Pursuant to a stockholders agreement between ETE and ETP, ETP controls Holdco. Consequently, ETP consolidates Holdco (including Sunoco and Southern Union) in its financial statements subsequent to consummation of the Holdco Transaction. Prior to the contribution of Sunoco to Holdco, Sunoco contributed $2.0 billion of cash and its interests in Sunoco Logistics to ETP in exchange for 90,706,000 Class F Units representing limited partner interests in ETP ("Class F Units"). The Class F Units are entitled to 35% of the quarterly cash distribution generated by ETP and its subsidiaries other than Holdco, subject to a maximum cash distribution of $3.75 per Class F Unit per year, which is the current distribution level.
- In December 2012, we announced that Southern Union, has entered into definitive purchase and sale agreements dated December 14, 2012 (collectively, the “Purchase and Sale Agreements”) with each of Plaza Missouri Acquisition, Inc. (“Laclede Missouri”) and Plaza Massachusetts Acquisition, Inc. (“Laclede Massachusetts”), both of which are subsidiaries of Laclede Gas Company, Inc. (together, the “Laclede Entities”), pursuant to which Laclede Missouri has agreed to acquire the assets of Southern Union's Missouri Gas Energy division, and Laclede Massachusetts has agreed to acquire the assets of Southern Union's New England Gas Company division. Total consideration for the acquisitions will be $1.04 billion, subject to customary closing adjustments, less the assumption of approximately $19 million of debt. On February 11, 2013, the Laclede Entities announced that it had entered into an agreement with Algonquin Power & Utilities Corp ("APUC") that will allow a subsidiary of APUC to assume the right of the Laclede Entities to purchase the assets of Southern Union's New England Gas Company division, subject to certain approvals. It is expected that the transactions contemplated by the Purchase and Sale Agreements will close by the end of the third quarter of 2013.
- On February 27, 2013, Southern Union entered into a definitive contribution agreement to contribute to Regency all of the issued and outstanding membership interest in Southern Union Gathering Company, LLC, and its subsidiaries, including SUGS. The consideration to be paid by Regency in connection with this transaction will consist of (i) the issuance of 31,372,419 Regency common units to Southern Union, (ii) the issuance of 6,274,483 Regency Class F units to Southern Union, (iii) the distribution of $570 million in cash to Southern Union, and (iv) the payment of $30 million in cash to a subsidiary of ETP. The Regency Class F units will have the same rights, terms and conditions as the Regency common units, except that Southern Union will not receive distributions on the Regency Class F units for the first eight consecutive quarters following the closing, and the Regency Class F units will thereafter automatically convert into Regency common units on a one-for-one basis. Upon the closing of the transaction, ETE will agree to forego all distributions with respect to its IDRs on the Regency common units issued in the transaction for the first eight consecutive quarters following the closing. The transaction is expected to close in the second quarter of 2013.

Significant Organic Growth Projects

Our significant organic growth projects in 2012 included the following, as discussed in more detail herein:

- Completed construction of the 570-mile, 209,000 Bbls/d Lone Star West Texas Gateway NGL Pipeline ahead of schedule. The West Texas Gateway NGL Pipeline was placed in service on December 4, 2012. The 130-mile Justice NGL Pipeline, extending from the Jackson County processing facility to Mont Belvieu, which was also recently placed in service, provides 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 20-inch pipeline is approximately 340,000 Bbls/d.
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Completed construction of the 200 MMcf/d Karnes County Processing Plant, and Phase I of the Jackson Plant, which will provide an additional 400 MMcf/day of capacity upon completion in the first quarter of 2013.

- In September 2012, we placed in service 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 has an initial capacity of 450 MMcf/d, with anticipated capacity expansion exceeding 550 MMcf/d. As part of the pipeline project, we will also construct a new 200 MMcf/d 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.

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- In December 2012, we announced that Lone Star's 100,000 Bbls/d NGL fractionation facility at Mont Belvieu, Texas is now in service. 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. 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.
- Lone Star previously 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 fourth quarter of 2013.
- To facilitate existing long-term fee-based agreements, which include volume commitments in excess of 540,000 MMBtu/d of natural gas, we expanded the previously announced REM pipeline in south Texas and will construct a new processing facility in Jackson County, Texas. The REM pipeline expansion, which extends from our Chisholm Pipeline in DeWitt County east into Jackson County, Texas, added approximately 70 miles of 42-inch pipe to the initial 160-mile, 30-inch pipeline. We placed the REM expansion in service in the third quarter of 2012. The first phase of the Jackson County gas processing plant is scheduled for completion in the first quarter of 2013.
- Growth projects placed into service during 2012 totaled $2.30 billion and we have announced growth projects aggregating $1 billion that are expected to be placed in service through 2014.
- We are currently studying the commercial and engineering feasibility of constructing a liquefaction facility at Southern Union's existing Lake Charles LNG regasification terminal. The project is anticipated to utilize a portion of the existing LNG regasification infrastructure, including storage tanks and marine facilities, and is expected to have the capacity to export up to 15 million tons per annum of LNG. We expect to complete certain studies, permits and approvals through 2014, and we do not anticipate making any significant capital expenditures related to this project prior to the completion of those items.
- We are currently developing plans to convert existing pipeline assets from natural gas transportation to crude oil transportation. These plans include the proposed abandonment of certain pipeline segments of Trunkline Gas Company, LLC (“Trunkline”), a subsidiary of Southern Union, which are currently operating in natural gas service, and the conversion of some or all of those segments of pipeline to crude oil transportation service. Trunkline's application to abandon those segments of pipeline from natural gas service, filed July 26, 2012, is currently pending before the FERC. As of February 13, 2013, the Partnership and Enbridge (U.S.), Inc. entered into an agreement under which they will jointly market a project to transport up to 420,000 Bbls/d of crude oil from Patoka, Illinois, to refinery markets in and around Memphis, Tennessee, Baton Rouge, Louisiana, and St. James, Louisiana, utilizing a combination of newly constructed pipeline and approximately 574 miles of pipeline to be abandoned by Trunkline. Subject to receipt of sufficient customer commitments for long-term transportation capacity and regulatory approvals, this project is expected to be in service by 2015.

Segment Overview

Our reportable segments changed in the fourth quarter of 2012 as a result of the Sunoco merger and Holdco transaction completed in October 2012 and are as described below. See Note 14 to our consolidated financial statements for additional financial information about our segments.

Intrastate Transportation and Storage Segment

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. Through our intrastate transportation and storage segment, we own and operate approximately 7,800 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.

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 Kinder Morgan, Natural Gas Exchange, Inc., XTO Energy, Inc., Total Gas & Power North America and EDF Trading North America, Inc.

Interstate Transportation and Storage Segment

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. Through our interstate transportation and storage segment, we directly own and operate approximately 12,600 miles of interstate natural gas pipeline and have a 50% interest in the joint venture that owns the 185-mile Fayetteville Express pipeline. ETP also owns a 50% interest in Citrus which owns 100% of FGT, an approximately 5,400 mile pipeline system that extends from south Texas through the Gulf Coast to south Florida.

Our interstate transportation and storage segment includes Panhandle, a wholly owned subsidiary of Southern Union, which is owned by Holdco. Panhandle owns and operates a large natural gas open-access interstate pipeline network. The pipeline network, consisting of the PEPL, Trunkline and Sea Robin transmission systems, serves customers in the Midwest, Gulf Coast and Midcontinent United States with a comprehensive array of transportation and storage services. In connection with its natural gas pipeline transmission and storage systems, Panhandle has five natural gas storage fields located in Illinois, Kansas, Louisiana, Michigan and Oklahoma. Southwest Gas operates four of these fields and Trunkline operates one. Through Trunkline LNG, Panhandle owns and operates an LNG terminal in Lake Charles, Louisiana.

The results from our interstate transportation and storage segment are primarily derived from the fees we earn from natural gas transportation and storage services. The major customers on our interstate pipelines include Chesapeake Energy Marketing, Inc., EnCana Marketing (USA), Inc. ("EnCana"), Shell Energy North America (US), L.P., BG LNG Services, ProLiance Energy, LLC and Petrohawk Energy Corporation.

Midstream Segment

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 is generally characterized by regional competition based on the proximity of gathering systems and processing plants to natural gas producing wells.

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 transports it to larger pipelines for further transportation.

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 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.

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.
Through our midstream segment, we own and operate approximately 6,700 miles of in service natural gas and NGL gathering pipelines, 4 natural gas processing plants, 15 natural gas treating facilities and 3 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 and Woodford Shale in North Texas, the Bossier Sands in East Texas, 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, ConocoPhillips Company, Andrews Oil Buyers, Inc and Chevron Phillips Chemical Company LP.
SUGS' operations consist of a network of natural gas and NGL pipelines, six processing plants and seven natural gas treating facilities. The principal assets of SUGS are located in the Permian Basin of Texas and New Mexico.
SUGS is primarily engaged in connecting producing wells of exploration and production (E&P) companies to its gathering system, providing compression and gathering services, treating natural gas to remove impurities to meet pipeline quality specifications, processing natural gas for the removal of NGL, and redelivering natural gas and NGLs to a variety of markets. SUGS' natural gas supply contracts primarily include fee-based, percent-of-proceeds, and margin sharing contracts (conditioning fee and wellhead purchase contracts). SUGS' primary sales customers include E&P companies, power generating companies, electric and natural gas utilities, energy marketers, industrial end-users located primarily in the Gulf Coast and southwestern United States, and petrochemicals. With respect to customer demand for the products and services it provides, SUGS' business is not generally seasonal in nature; however, SUGS' operations and the operations of its E&P producers can be adversely impacted by severe weather.
NGL Transportation and Services Segment
NGL transportation pipelines transport mixed NGLs and other hydrocarbons from natural gas processing facilities to fractionation plants and storage facilities. 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 fractionators separate mixed NGL streams into purity products, such as ethane, propane, normal butane, isobutane and natural gasoline.
Through our NGL transportation and services segment we own and operate approximately 300 miles of NGL pipelines and have a 50% interest in the Liberty pipeline, an approximately 85-mile NGL pipeline. We also have a 70% interest in Lone Star, which owns approximately 2,000 miles of NGL pipelines, three NGL processing plants, two fractionation facilities and NGL storage facilities with aggregate working storage capacity of approximately 47 million Bbls. One of the fractionation facilities and the NGL storage facilities are located at Mont Belvieu, Texas, and the NGL pipelines primarily transport NGLs from the Permian and Delaware basins and the Barnett and Eagle Ford Shales to Mont Belvieu.
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.

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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, Louis Dreyfus Highbridge Energy LLC (subsequently renamed Castleton Commodities International, LLC) and The Williams Companies, Inc.

Investment in Sunoco Logistics

The Partnership's interests in Sunoco Logistics consist of a 2% general partner interest, 100% of the incentive distribution rights and 33,530,637 Sunoco Logistics common units representing 32% of the limited partner interests in Sunoco Logistics as of December 31, 2012. Because the Partnership controls Sunoco Logistics through its ownership of the general partner, the operations of Sunoco Logistics are consolidated into the Partnership. These operations are reflected by the Partnership in the investment in Sunoco Logistics segment.

Sunoco Logistics operates crude oil pipelines, crude oil acquisition and marketing, terminal facilities and refined products pipelines primarily in the northeast, midwest and southwest regions of the United States. In addition, the investment in Sunoco Logistics segment has ownership interests in several refined product pipeline joint ventures.

Sunoco Logistics' crude oil pipelines transport crude oil principally in Oklahoma and Texas. Crude oil transportation pipelines primarily deliver to and connect with other pipelines that deliver crude oil to a number of third-party refineries. Sunoco Logistics' crude oil pipelines consist of approximately 4,900 miles of crude oil trunk pipelines and approximately 500 miles of crude oil gathering lines that supply the trunk pipelines.

Sunoco Logistics' crude oil acquisition and marketing business gathers, purchases, markets and sells crude oil principally in the mid-continent United States, utilizing its fleet of approximately 200 crude oil transport trucks, approximately 120 crude oil truck unloading facilities and third-party assets.

Sunoco Logistics' refined terminal facilities receive refined products from pipelines, barges, railcars and trucks and transfer them to or from storage or transportation systems, such as pipelines, to other transportation systems, such as trucks or other pipelines. Sunoco Logistics' terminal facilities consist of an aggregate crude oil and refined petroleum products capacity of approximately 40 million barrels, including the 22 million barrel Nederland, Texas crude oil terminal; the 5 million barrel Eagle Point, New Jersey refined petroleum products and crude oil terminal; approximately 40 active refined petroleum products marketing terminals located in the northeast, midwest and southwest United States; and several refinery terminals located in the northeast United States.

Sunoco Logistics' refined product pipelines transport refined products including multiple grades of gasoline, middle distillates (such as heating oil, diesel and jet fuel) and LPGs (such as propane and butane) from refineries to markets. Sunoco Logistics' refined products pipelines consist of approximately 2,500 miles of refined product pipelines and joint venture interests in four refined products pipelines in selected areas of the United States.

Retail Marketing

Our retail marketing and wholesale distribution business segment consists of Sunoco's marketing operations, which sell gasoline and middle distillates at retail and operates convenience stores in 25 states, primarily on the east coast and in the midwest region of the United States. The highest concentrations of outlets are located in Connecticut, Florida, Maryland, Massachusetts, Michigan, New Jersey, New York, Ohio, Pennsylvania and Virginia.

All Other

Segments below the quantitative thresholds are classified as “All Other.” These include the following:

- 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.

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- We 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.
- We own a 32% limited partner interest in AmeriGas, which is engaged in retail propane marketing. We acquired this interest when we contributed our retail propane operations to AmeriGas in January 2012. Our retail propane operations were previously reflected as a separate reportable segment.
- Southern Union has operations providing local distribution of natural gas in Missouri and Massachusetts. The operations are conducted through the Southern Union's operating divisions: Missouri Gas Energy and New England Gas Company. As noted in "Strategic Transactions" above, we recently entered into an agreement to sell these operations.
- Sunoco owns an approximate 30% non-operating interest in Philadelphia Energy Solutions ("PES"), a joint venture with The Carlyle Group, L.P. ("The Carlyle Group"), which owns a refinery in Philadelphia. Sunoco has a ten-year supply contract for gasoline and diesel produced at the refinery for its retail marketing business.

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 2,875 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 550 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.

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 extend through 2017.

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
- Bi-directional capabilities

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.

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HPL System

- Capacity of 5.3 Bcf/d
- Approximately 3,900 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, 2012, we had approximately 12.4 Bcf committed under fee-based arrangements with third parties and approximately 45.7 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 680,000 MMBtu/d and 260,000 MMBtu/d, respectively.

Interstate Transportation Pipelines

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

Florida Gas Transmission Pipeline

- Capacity of 3.1 Bcf/d
- Approximately 5,400 miles of interstate natural gas pipeline
- FGT is owned by Citrus, a 50/50 joint venture with Kinder Morgan, Inc. ("KMI")

The Florida Gas Transmission pipeline is an open-access interstate pipeline system with a mainline capacity of 3.1 Bcf/d and approximately 5,400 miles of pipelines extending from south Texas through the Gulf Coast region of the United States to south Florida. The Florida Gas Transmission pipeline system receives natural gas from various onshore and offshore natural gas producing basins. FGT is the principal transporter of natural gas to the Florida energy market, delivering over 64% of the natural gas consumed in the state. In addition, Florida Gas Transmission's pipeline system operates and maintains over 70 interconnects with major interstate and intrastate natural gas pipelines, which provide FGT's customers access to diverse natural gas producing regions.

FGT's customers include electric utilities, independent power producers, industrials and local distribution companies.

Transwestern Pipeline

- Capacity of 2.0 Bcf/d
- Approximately 2,560 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

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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.

Panhandle Eastern Pipeline

- Capacity of 2.8 Bcf/d
- Approximately 6,000 miles of interstate natural gas pipeline

The Panhandle Eastern pipeline's transmission system consists of four large diameter pipelines extending approximately 1,300 miles from producing areas in the Anadarko Basin of Texas, Oklahoma and Kansas through Missouri, Illinois, Indiana, Ohio and into Michigan. Panhandle Eastern pipeline is owned by a subsidiary of Holdco.

Trunkline Gas Pipeline

- Capacity of 1.7 Bcf/d
- Approximately 3,000 miles of interstate natural gas pipeline

The Trunkline Gas pipeline's transmission system consists of two large diameter pipelines extending approximately 1,400 miles from the Gulf Coast areas of Texas and Louisiana through Arkansas, Mississippi, Tennessee, Kentucky, Illinois, Indiana and to Michigan. Trunkline Gas pipeline is owned by a subsidiary of Holdco.

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 through ETC FEP 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.

Sea Robin Pipeline

- Capacity of 1.9 Bcf/d
- Approximately 1,000 miles of interstate natural gas pipeline

The Sea Robin pipeline's transmission system consists of two offshore Louisiana natural gas supply systems extending approximately 81 miles into the Gulf of Mexico. Sea Robin pipeline is owned by a subsidiary of Holdco.

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Midstream

The following details our assets in the midstream segment.

Southeast Texas System

- Approximately 6,200 miles of natural gas pipeline
- One natural gas processing plant (La Grange) with aggregate capacity of 205 MMcf/d
- 12 natural gas treating facilities with aggregate capacity of 1.8 Bcf/d
- One natural gas conditioning facility with aggregate capacity of 200 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 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.

The La Grange processing plant is a natural gas processing plant that processes the rich natural gas that flows through our system to produce residue gas and NGLs. Residue gas is delivered into our intrastate pipelines and NGLs are delivered into our recently acquired or completed pipelines.

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.

SUGS

- Approximately 5,700 miles of natural gas and NGL pipelines
- Six processing plants with aggregate capacity of 510 MMcf/d
- Seven natural gas treating facilities with aggregate capacity of 630 MMcf/d

SUGS owns natural gas and NGL pipelines, processing plants and natural gas treating plants and is engaged in connecting producing wells of exploration and production companies to its gathering system, treating natural gas to remove impurities to meet pipeline quality specifications, processing natural gas for the removal of NGLs and redelivering natural gas and NGLs to a variety of markets in West Texas and New Mexico. SUGS is owned by a subsidiary of Holdco.

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 and Woodford Shales. 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 processing plant and a conditioning facility.

Northern Louisiana

- Approximately 280 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.

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Rich Eagle Ford Mainline System

- Approximately 220 miles of natural gas pipeline
- Two processing plants (Chisholm and Kenedy) with capacity of 325 MMcf/d

The Rich Eagle Ford Mainline gathering system consists of 30-inch and 42-inch natural gas transportation pipelines delivering 1.0 Bcf/d of capacity originating in Dimmitt County, Texas and extending to our Chisholm pipeline for ultimate deliveries to our existing processing plants. Our Chisholm and Kenedy processing plants are connected to our intrastate transportation pipeline systems for deliveries of residue gas and are also connected with our NGL pipelines for delivery of NGLs.

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.

NGL Transportation and Services

The following details our assets in the NGL transportation and services segment. Certain assets described below are owned by Lone Star, a joint venture with Regency 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, owned by Lone Star, 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.

West Texas Gateway Pipeline

- Initial capacity of 209,000 Bbls/d
- Approximately 570 miles of NGL transmission pipeline

The West Texas Gateway Pipeline, owned by Lone Star, began service in December 2012 and transports NGLs produced in the Permian and Delaware Basins in West Texas and the Eagle Ford Shale to Mont Belvieu, Texas.

Other NGL Pipelines

- Capacity ranging from 20,000 to 260,000 Bbls/d
- Approximately 279 miles of NGL transmission pipelines

Other NGL pipelines include the 126-mile Justice pipeline with capacity of 260,000 Bbls/d, the 87-mile Liberty pipeline with a capacity of 90,000 Bbls/d, the 45-mile Freedom pipeline with a capacity of 40,000 Bbls/d and the 21-mile Spirit pipeline with a capacity of 20,000 Bbls/d.

Mont Belvieu Facilities

- Working storage capacity of approximately 43 million Bbls
- Approximately 140 miles of NGL transmission pipelines
- 100,000 Bbls/d fractionation facility

The Mont Belvieu storage facility, owned by Lone Star, 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.

The Long Star Fractionator I, completed in December 2012, handles NGLs delivered from several sources, including Lone Star's West Texas Gateway pipeline and the Justice pipeline.

Hattiesburg Storage Facility

- Working storage capacity of 4 million Bbls

The Hattiesburg storage facility, owned by Lone Star, is an integrated liquids storage facility with approximately 4 million Bbls of salt dome capacity, providing 100% fee-based cash flows.

Sea Robin Processing Plant

- One processing 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 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

- Two processing plants (the Chalmette and Sorrento Plants) with a total capacity of 82 MMcf/d
- One NGL fractionator with 25,000 Bbls/d capacity
- Approximately 100 miles of NGL pipelines

Refinery Services, owned by Lone Star, 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 processing plants.

Investment in Sunoco Logistics

Sunoco Logistics is principally engaged in the transport, terminalling and storage of crude oil and refined petroleum products. In addition to logistics services, Sunoco Logistics owns acquisition and marketing assets which are used to facilitate the purchase and sale of crude oil and refined products. Its portfolio of geographically diverse assets earns revenues in 30 states located throughout the United States. Sunoco Logistics also has an ownership interest in several refined product and crude oil pipeline joint ventures.

The following details the assets owned by Sunoco Logistics.

Crude Oil Pipelines

Sunoco Logistics' crude oil pipelines consist of approximately 4,900 miles of crude oil trunk pipelines and approximately 500 miles of crude oil gathering pipelines in the southwest and midwest United States. These lines primarily deliver crude oil and other feedstocks to refineries in those regions. Following is a description of Sunoco Logistics' crude pipelines:

- West Texas Gulf Pipe Line Company owns approximately 600 miles of common carrier crude oil pipelines, which originate from the West Texas oil fields at Colorado City and the Nederland Terminal and extend to Longview, Texas where deliveries are made to several pipelines, including the Mid-Valley pipeline.
- Mid-Valley Pipeline Company owns approximately 1,000 miles of crude oil pipelines, which originate in Longview, Texas and terminate in Samaria, Michigan. Mid-Valley provides crude oil to a number of refineries, primarily in the midwest United States.

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- The Southwest United States pipeline system consists of approximately 2,950 miles of crude oil trunk pipelines and approximately 300 miles of crude oil gathering pipelines in Texas. The Texas system is connected to the Mid-Valley pipeline, the West Texas Gulf pipeline, other third-party pipelines and our Nederland Terminal.
- The Oklahoma crude oil pipeline and gathering system contains approximately 850 miles of crude oil trunk pipelines and approximately 200 miles of crude oil gathering pipelines. We have the ability to deliver substantially all of the crude oil gathered on our Oklahoma system to Cushing, Oklahoma.
- The Midwest United States pipeline system consists of approximately 1,000 miles of a crude oil pipeline that originates in Longview, Texas and passes through Louisiana, Arkansas, Mississippi, Tennessee, Kentucky and Ohio, and terminates in Samaria, Michigan. This pipeline provides crude oil to a number of refineries, primarily in the midwest United States.

Sunoco Logistics also owns approximately 100 miles of crude oil pipeline that runs from Marysville, Michigan to Toledo, Ohio, and a truck injection point for local production at Marysville. This pipeline receives crude oil from the Enbridge pipeline system for delivery to refineries located in Toledo, Ohio and to Marathon's Samaria, Michigan tank farm, which supplies its refinery in Detroit, Michigan.

Sunoco Logistics' pipelines access several trading hubs, including the largest trading hub for crude oil in the United States located in Cushing, Oklahoma, as well as other trading hubs located in Midland, Colorado City and Longview, Texas. Our crude oil pipelines also deliver to and connect with other pipelines that deliver crude oil to a number of third-party refineries.

Crude Oil Acquisition and Marketing

Sunoco Logistics' crude oil acquisition and marketing activities include the gathering, purchasing, marketing and selling of crude oil primarily in the mid-continent United States. The operations are conducted using approximately 200 crude oil transport trucks and third-party assets and approximately 120 crude oil truck unloading facilities. Sunoco Logistics' crude oil truck drivers pick up crude oil at production lease sites and transport it to various truck unloading facilities on our pipelines and third-party pipelines. Third-party trucking firms are also retained to transport crude oil to certain facilities.

Terminal Facilities

Sunoco Logistics' 41 active refined products terminals receive refined products from pipelines, barges, railcars, and trucks and distribute them to Sunoco and to third parties, who in turn deliver them to end-users and retail outlets. Terminals are facilities where products are transferred to or from storage or transportation systems, such as a pipeline, to other transportation systems, such as trucks or other pipelines. The operation of these facilities is called "terminalling." Terminals play a key role in moving product to the end-user markets by providing the following services: storage; distribution; blending to achieve specified grades of gasoline and middle distillates; and other ancillary services that include the injection of additives and the filtering of jet fuel. Typically, Sunoco Logistics' refined products terminal facilities consist of multiple storage tanks and are equipped with automated truck loading equipment that is operational 24 hours a day. This automated system provides controls over allocations, credit, and carrier certification.

- The East Boston Terminal is a refined products terminal, located in East Boston, Massachusetts, that receives refined products from affiliates of ConocoPhillips. The terminal is the sole service provider to Logan International Airport under a long-term contract to provide jet fuel. The terminal includes a 10-bay truck rack and total active storage capacity for this facility is approximately 1 million barrels.
- The Eagle Point Tank farm is located in Westville, New Jersey and consists of approximately 5 million barrels of active storage for clean products and dark oils.
- The Southwest Terminal is a crude oil and refined products terminal located in Bay City, Texas. The terminal has a total capacity of less than half of a million barrels.
- A butane blending business generates profits by adding less expensive normal butane to higher priced gasoline, while complying with regional and seasonally variable specifications for maximum vapor pressure. The business provides terminal and pipeline operators with the use of proprietary automated blending systems and butane supply to optimize butane blending in pipelines and at refined products terminals.

Sunoco Logistics' refined products terminals derive revenues from terminalling fees paid by customers. A fee is charged for receiving refined products into the terminal and delivering them to trucks, barges, or pipelines. In addition to terminalling fees, Sunoco Logistics generates revenues by charging customers fees for blending services, including ethanol and biodiesel blending, injecting additives, and filtering jet fuel. Sunoco Logistics' refined products pipelines supply the majority of its refined products terminals, with third-party pipelines and barges supplying the remainder.

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The following table outlines the number of Sunoco Logistics' active terminals and storage capacity by state:

State	Number of Terminals	Storage Capacity (thousands of Bbls)
Indiana	1	206
Maryland	1	715
Massachusetts	1	1,160
Michigan	3	762
New Jersey	4	746
New York [1]	4	920
Ohio	7	904
Pennsylvania	13	1,734
Virginia	1	403
Louisiana	1	161
Texas	5	715
Total	41	8,426

(1) Sunoco Logistics owns a 45% ownership interest in a terminal at Inwood, New York and a 50% ownership interest in a terminal at Syracuse, New York. The storage capacities included in the table represent the proportionate share of capacity attributable to Sunoco Logistics' ownership interests in these terminals.

Sunoco Logistics' Nederland Terminal, which is located on the Sabine-Neches waterway between Beaumont and Port Arthur, Texas, is a large marine terminal providing storage and distribution services for refiners and other large transporters of crude oil. The terminal receives, stores, and distributes crude oil, feedstocks, lubricants, petrochemicals, and bunker oils (used for fueling ships and other marine vessels), and also blends lubricants. The terminal currently has a total storage capacity of approximately 22 million barrels in approximately 130 aboveground storage tanks with individual capacities of up to 660,000 barrels.

Sunoco Logistics' Fort Mifflin Terminal Complex is located on the Delaware River in Philadelphia and includes the Fort Mifflin Terminal, the Hog Island Wharf, the Darby Creek tank farm and connecting pipelines. Revenues are generated from the Fort Mifflin Terminal Complex by charging fees based on throughput.

Sunoco Logistics' Marcus Hook tank farm has a total storage capacity of approximately 2 million barrels.

Sunoco Logistics' Eagle Point Terminal docks are located in Westville, New Jersey on the Delaware River and are connected to the Sunoco Eagle Point refinery, which was permanently shut down in the fourth quarter 2009. To complement the services offered by Sunoco Logistics' existing dock and truck loading equipment, Sunoco Logistics acquired the Eagle Point tank farm from Sunoco in July 2011. The tank farm is connected to Sunoco Logistics' previously owned dock facility and allowed us to expand upon the services offered by its existing assets. The tank farm provides crude oil and refined products storage and distribution services and has a total active storage capacity of approximately 5 million barrels for clean products and dark oils. The docks can accommodate three ships or barges to receive and deliver crude oil, intermediate products and refined products to outbound ships and barges.

Sunoco Logistics' Inkster Terminal, located near Detroit, Michigan, consists of eight salt caverns with a total storage capacity of approximately 975,000 barrels. The Inkster Terminal's storage is used in connection with the Toledo, Ohio to Sarnia, Canada pipeline system and for the storage of LPGs from Canada and a refinery in Toledo. The terminal can receive and ship LPGs in both directions at the same time and has a propane truck loading rack.

Refined Products Pipelines

Sunoco Logistics owns and operates approximately 2,500 miles of refined products pipelines in selected areas of the United States. The refined products pipelines transport refined products from refineries in the northeast, midwest and southwest United States to markets in New York, New Jersey, Pennsylvania, Ohio, Michigan, Massachusetts, Texas and Canada. The refined products transported in these pipelines include multiple grades of gasoline, middle distillates (such as heating oil, diesel and jet fuel) and LPGs (such as propane and butane). Rates for shipments on the refined products pipelines are regulated by the FERC and the Pennsylvania Public Utility Commission (“PA PUC”), among other state regulatory agencies.

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Inland Corporation is Sunoco Logistics' 83.8% owned joint venture consisting of 350 miles of active refined products pipelines in Ohio. The pipeline connects three refineries in Ohio to terminals and major markets in Ohio. As Sunoco Logistics owns a

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controlling financial interest in Inland, the joint venture is reflected as a consolidated subsidiary in its consolidated financial statements.

Sunoco Logistics owns equity interests in several common carrier refined products pipelines, summarized in the following table:

Pipeline	Equity Ownership	Pipeline Mileage
Explorer Pipeline Company [1]	9.4 %	1,850
Yellowstone Pipe Line Company [2]	14.0 %	700
West Shore Pipe Line Company [3]	17.1 %	650
Wolverine Pipe Line Company [4]	31.5 %	700

(1) The system, which is operated by Explorer employees, originates from the refining centers of Lake Charles, Louisiana and Beaumont, Port Arthur and Houston, Texas, and extends to Chicago, Illinois, with delivery points in the Houston, Dallas/Fort Worth, Tulsa, St. Louis, and Chicago areas. Explorer charges market-based rates for all its tariffs.

(2) The system, which is operated by Phillips 66, originates from the Billings, Montana refining center and extends to Moses Lake, Washington with delivery points along the way. Tariff rates are regulated by the FERC for interstate shipments and the Montana Public Service Commission for intrastate shipments in Montana.

(3) The system, which is operated by Buckeye Partners, L.P., originates from the Chicago, Illinois refining center and extends to Madison and Green Bay, Wisconsin with delivery points along the way. West Shore charges market-based tariff rates in the Chicago area.

(4) The system, which is operated by Wolverine employees, originates from Chicago, Illinois and extends to Detroit, Grand Haven, and Bay City, Michigan with delivery points along the way. Wolverine charges market-based rates for tariffs at the Detroit, Jackson, Niles, Hammond, and Lockport destinations.

Sunoco has agreements with Sunoco Logistics which establish fees for administrative services provided by Sunoco to Sunoco Logistics and provide indemnifications by Sunoco for certain environmental, toxic tort and other liabilities.

Retail Marketing

The retail marketing segment consists of the retail sale of gasoline and middle distillates and the operation of convenience stores in 25 states, primarily on the east coast and in the midwest region of the United States. The highest concentrations of outlets are located in Connecticut, Florida, Maryland, Massachusetts, Michigan, New Jersey, New York, Ohio, Pennsylvania and Virginia.

Retail marketing has a portfolio of outlets that differ in various ways including: product distribution to the outlets; site ownership and operation; and types of products and services provided.

Direct outlets may be operated by Sunoco or by an independent dealer, and are sites at which fuel products are delivered directly to the site by Sunoco trucks or by contract carriers. Sunoco or an independent dealer owns or leases the property. These sites may be traditional locations that sell fuel products under the Sunoco® and Coastal® brands or may include APlus® convenience stores or Ultra Service Centers® that provide automotive diagnostics and repair. Included among the direct outlets at December 31, 2012 were 73 outlets on turnpikes and expressways in Pennsylvania, New Jersey, New York, Maryland, Ohio and Delaware. Of these outlets, 57 were Sunoco-operated sites providing gasoline, diesel fuel and convenience store merchandise.

Distributor outlets are sites in which the distributor takes delivery of fuel products at a terminal where branded products are available. Sunoco does not own, lease or operate these locations.

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The following table sets forth Sunoco's retail gasoline outlets at December 31, 2012:

Direct Outlets:	
Sunoco-Owned or Leased:	
Sunoco Operated:	
Traditional	60
APlus® Convenience Stores	377
	437
Dealer Operated:	
Traditional	127
APlus® Convenience Stores	233
Ultra Service Centers®	91
	451
Total Sunoco-Owned or Leased [(1)]	888
Dealer Owned [(2)]	495
Total Direct Outlets	1,383
Distributor Outlets	3,605
	4,988

(1) Gasoline and diesel throughput per Sunoco-operated site averaged 198,000 gallons per month from the merger date.

(2) Primarily traditional outlets.

Branded fuels sales (including middle distillates) averaged 318,000 Bbls/d from the merger date.

The Sunoco® brand is positioned as a premium brand. Brand improvements in recent years have focused on physical image, customer service and product offerings. In addition, Sunoco believes its brands and high performance gasoline business have benefited from its sponsorship agreements with NASCAR® and INDYCAR®. Under the sponsorship agreement with NASCAR, which continues until 2019, Sunoco® is the Official Fuel of NASCAR® and APlus® is the Official Convenience Store of NASCAR®. Sunoco has exclusive rights to use certain NASCAR® trademarks to advertise and promote Sunoco products and is the exclusive fuel supplier for the three major NASCAR® racing series. Sunoco has an agreement to be the Official Fuel of the INDYCAR® series through the 2014 season.

Sunoco's APlus® convenience stores are located principally in Florida, New York and Pennsylvania. These stores supplement sales of fuel products with a broad mix of merchandise such as groceries, fast foods, beverages and tobacco products. The following table sets forth information concerning Sunoco's Company-operated APlus® convenience stores at December 31, 2012:

Number of stores	377	
Merchandise sales (thousands of dollars/store/month)	$106	
Merchandise margin (% sales)	26	%

Business Strategy

We have designed our business strategy with the goal of creating and maximizing value to our Unitholders. 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 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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Following is a summary of the business strategies of our core 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 while supporting our investment grade credit ratings.

Competition

Natural Gas

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.

NGL

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.

Crude and Refined Product

In markets served by our refined products and crude oil pipelines, we face competition with other pipelines.
Generally, pipelines are the lowest cost method for long-haul, overland movement of refined products. Therefore, the most significant competitors for large volume shipments in the areas served by our pipelines are other pipelines. In addition, pipeline operations face competition from trucks that deliver product in a number of areas that our pipeline operations serve. While their costs may not be competitive for longer hauls or large volume shipments, trucks compete effectively for incremental and marginal volume in many areas served by our pipelines.

We also face competition among common carrier pipelines carrying crude oil. This competition is based primarily on transportation charges, access to crude oil supply and market demand. Similar to pipelines carrying refined products, the high capital costs deter competitors for the crude oil pipeline systems from building new pipelines. Crude oil purchasing and marketing activities’ competitive factors are price and contract flexibility, quantity and quality of services, and accessibility to end markets.

Our refined product terminals compete with other independent terminals with respect to price, versatility and services provided. The competition primarily comes from integrated petroleum companies, refining and marketing companies, independent terminal companies and distribution companies with marketing and trading operations.

We face strong competition in the market for the sale of retail gasoline and merchandise. Our competitors include service stations of large integrated oil companies, independent gasoline service stations, convenience stores, fast food stores, and other similar

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retail outlets, some of which are well-recognized national or regional retail systems. The number of competitors varies depending on the geographical area. It also varies with gasoline and convenience store offerings. The principal competitive factors affecting our retail marketing operations include gasoline and diesel acquisition costs, site location, product price, selection and quality, site appearance and cleanliness, hours of operation, store safety, customer loyalty and brand recognition. We compete by pricing gasoline competitively, combining retail gasoline business with convenience stores that provide a wide variety of products, and using advertising and promotional campaigns. We believe that we are in a position to compete effectively as a marketer of refined products because of the location of our retail network, which is well integrated with the distribution system operated by Sunoco Logistics.

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 non-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, 2012, none of our customers individually accounted for more than 10% of our consolidated revenues.

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 Florida Gas Transmission, Transwestern, Panhandle Eastern, Trunkline Gas, Tiger, Fayetteville Express and Sea Robin pipelines transport natural gas in interstate commerce and thus each qualifies as a "natural-gas company" under the NGA subject to the FERC's regulatory jurisdiction. We also hold certain storage facilities that are subject to the FERC's 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

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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 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.

In July 2010, in response to an intervention and protest filed by BG LNG Services (BGLS) regarding its rates with Trunkline LNG applicable to certain LNG expansions, FERC determined that there was no reason at that time to expend FERC's resources on a rate proceeding with respect to Trunkline LNG even though cost and revenue studies provided by the Company to FERC indicated Trunkline LNG's revenues were in excess of its associated cost of service. However, since the current fixed rates expire at the end of 2015 and revert to tariff rate for these LNG expansions as well as the base LNG facilities for which rates were set in 2002, a rate proceeding could be initiated at that time and result in significant revenue reductions if the cost of service remains lower than revenues.

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.

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 and 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 and 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

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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. 5th 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 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 and West Virginia 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.

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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 Interstate Crude Oil and Refined Products Pipelines. Interstate common carrier pipeline operations are subject to rate regulation by FERC under the Interstate Commerce Act, the Energy Policy Act of 1992, and related rules and orders. The Interstate Commerce Act requires that tariff rates for petroleum pipelines be "just and reasonable" and not unduly discriminatory. This statute also permits interested persons to challenge proposed new or changed rates and authorizes FERC to suspend the effectiveness of such rates for up to seven months and to investigate such rates. If, upon completion of an investigation, FERC finds that the new or changed rate is unlawful, it is authorized to require the carrier to refund revenues in excess of the prior tariff during the term of the investigation. FERC also may investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Upon an appropriate showing, a shipper may obtain reparations for damages sustained for a period of up to two years prior to the filing of a complaint.

FERC generally has not investigated interstate rates on its own initiative when those rates, like those we charge, have not been the subject of a protest or a complaint by a shipper. However, FERC could investigate our rates at the urging of a third party if the third party is either a current shipper or has a substantial economic interest in the tariff rate level. Although no assurance can be given that the tariffs charged by us ultimately will be upheld if challenged, management believes that the tariffs now in effect for our pipelines are within the maximum rates allowed under current FERC guidelines.

We have been approved by FERC to charge market-based rates in most of the refined products locations served by our pipeline systems. In those locations where market-based rates have been approved, we are able to establish rates that are based upon competitive market conditions.

Regulation of Intrastate Crude Oil and Refined Products Pipelines. Some of our crude oil and refined products pipelines are subject to regulation by the Texas R.R.C., the P A PUC, and the OCC. The operations of our joint venture interests are also subject to regulation in the states in which they operate. The applicable state statutes require that pipeline rates be nondiscriminatory and provide no more than a fair return on the aggregate value of the pipeline property used to render services. State commissions generally have not initiated an investigation of rates or practices of petroleum pipelines in the absence of shipper complaints. Complaints to state agencies have been infrequent and are usually resolved informally. Although management cannot be certain that our intrastate rates ultimately would be upheld if challenged, we believe that, given this history, the tariffs now in effect are not likely to be challenged or, if

challenged, are not likely to be ordered to be reduced.
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 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

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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.

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

General. Our operation of processing plants, pipelines and associated facilities, including compression, in connection with the gathering, processing, storage and transmission of natural gas and the storage and transportation of NGLs, crude oil and refined products is subject to stringent and complex federal, state and local laws and regulations, including those governing, among other things, air emissions, wastewater discharges, the use, management and disposal of hazardous and nonhazardous materials and wastes, and the cleanup of contamination. Noncompliance with such laws and regulations, or incidents resulting in environmental releases, could cause us to incur substantial costs, penalties, fines and other criminal sanctions, third party claims for personal injury or property damage, investments to retrofit or upgrade our facilities and programs, or curtailment of operations. As with the industry generally, compliance with existing and anticipated environmental laws and regulations increases our overall cost of doing business, including our cost of planning, constructing and operating our plants, pipelines and other facilities. Included in our construction and operation costs are capital cost items necessary to maintain or upgrade our equipment and facilities to remain in compliance with environmental laws and regulations.

We have implemented procedures to ensure that all governmental environmental approvals for both existing operations and those under construction are updated as circumstances require. We believe that our operations and facilities are in substantial compliance with applicable environmental laws and regulations and that the cost of compliance with such laws and regulations will not have a material adverse effect on our business, results of operations and financial condition. We cannot be certain, however, that identification of presently unidentified conditions, more rigorous enforcement by regulatory agencies, enactment of more stringent laws and regulations or other unanticipated events will not arise in the future and give rise to material environmental liabilities that could have a material adverse effect on our business, financial condition or results of operations.

Hazardous Substances and Waste Materials. To a large extent, the environmental laws and regulations affecting our operations relate to the release of hazardous substances and waste materials into soils, groundwater and surface water and include measures to prevent, minimize or remediate contamination of the environment. These laws and regulations generally regulate the generation, storage, treatment, transportation and disposal of hazardous substances and waste materials and may require investigatory and remedial actions at sites where such material has been released or disposed. For example, CERCLA, also known as the "Superfund" law, and comparable state laws, impose liability without regard to fault or the legality of the original conduct on certain classes of persons that contributed to a release of a "hazardous substance" into the environment. These persons include the owner and operator of the site where a release occurred and companies that disposed or arranged for the disposal of the hazardous substance that has been released into the environment. Under CERCLA, these persons may be subject to joint and several liability, without regard to fault, for, among other things, the costs of investigating and remediating the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA and comparable state law also authorize the federal EPA, its state counterparts, and, in some instances, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. Although “petroleum” as well as natural gas and NGLs are excluded from CERCLA's definition of a “hazardous substance,” in the course of our ordinary operations we generate wastes that may fall within that definition or that may be subject to other waste disposal laws and regulations. We may be responsible under CERCLA or state laws for all or part of the costs required to clean up sites at which such substances or wastes have been disposed. We have received notification that we may be potentially responsible for cleanup costs under CERCLA at a site in Houston, Texas; however, these costs are not expected to be material.

We also generate both hazardous and nonhazardous wastes that are subject to requirements of the federal RCRA, and comparable state statutes. We are not currently required to comply with a substantial portion of the RCRA requirements at many of our facilities because the minimal quantities of hazardous wastes generated there make us subject to less stringent management standards. From time to time, the EPA has considered the adoption of stricter handling, storage and disposal standards for nonhazardous wastes, including crude oil and natural gas wastes. It is possible that some wastes generated by us that are currently classified as nonhazardous may in the future be designated as "hazardous wastes," resulting in the wastes being subject to more rigorous and costly disposal requirements, or that the full complement of RCRA standards could be applied to facilities that generate lesser amounts of hazardous waste. Changes in applicable regulations may result in a material increase in our capital expenditures or plant operating and maintenance expense.

We currently own or lease sites that have been used over the years by prior owners and by us for various activities related to gathering, processing, storage and transmission of natural gas, NGLs, crude oil and refined products. Solid waste disposal practices within the oil and gas industry have improved over the years with the passage and implementation of various environmental laws and regulations. Nevertheless, some hydrocarbons and wastes have been disposed of or released on or under various sites during the operating history of those facilities that are now owned or leased by us. Notwithstanding the possibility that these dispositions may have occurred during the ownership of these assets by others, these sites may be subject to CERCLA, RCRA and comparable state laws. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators) or contamination (including soil and groundwater contamination) or to prevent the migration of 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, 2012 and 2011, accruals of $211 million and $14 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, the predecessor owner's share of certain environmental liabilities of ETC OLP. The accrual also includes amounts related to Sunoco.

Sunoco is subject to extensive and frequently changing federal, state and local laws and regulations, including, but not limited to, those relating to the discharge of materials into the environment or that otherwise relate to the protection of the environment, waste management and the characteristics and composition of fuels. These laws and regulations require environmental assessment and/or remediation efforts at many of Sunoco's facilities and at formerly owned or third-party sites. Sunoco's accrual for environmental remediation activities amounted to $163 million at December 31, 2012. These legacy sites that are subject to environmental assessments include formerly owned terminals and other logistics assets, retail sites that Sunoco no longer operates, closed and/or sold refineries and other formerly owned sites. Following the signing of the merger agreement between ETP and Sunoco, Sunoco suspended their efforts to establish this environmental fund so that ETP could determine whether it wanted to pursue this project. At this time, no determinations have been made whether to establish this environmental fund.

Sunoco's accrual for environmental remediation activities reflects anticipated work at identified sites where an assessment has indicated that cleanup costs are probable and reasonably estimable. The accrual is undiscounted and is based on currently available information, estimated timing of remedial actions and related inflation assumptions, existing technology and presently enacted laws and regulations. It is often extremely difficult to develop reasonable estimates of future site remediation costs due to changing regulations, changing technologies and their associated costs, and changes in the economic environment. Engineering studies, historical experience and other factors are used to identify and evaluate remediation alternatives and their related costs in determining the estimated accruals for

environmental remediation activities. Losses attributable to unasserted claims are also reflected in the accruals to the extent they are probable of occurrence and reasonably estimable.
Under various environmental laws, including the Resource Conservation and Recovery Act (“RCRA”) (which relates to solid and hazardous waste treatment, storage and disposal), Sunoco has initiated corrective remedial action at its facilities, formerly owned facilities and third-party sites. At the Company’s major manufacturing facilities, Sunoco has consistently assumed continued industrial use and a containment/remediation strategy focused on eliminating unacceptable risks to human health or the environment. The remediation accruals for these sites reflect that strategy. Accruals include amounts to prevent off-site migration and to contain the impact on the facility property, as well as to address known, discrete areas requiring remediation within the plants. Activities include closure of RCRA solid waste management units, recovery of hydrocarbons, handling of impacted soil,

mitigation of surface water impacts and prevention of off-site migration. A change in this approach as a result of changing the intended use of a property or a sale to a third party could result in a higher cost remediation strategy in the future.

Sunoco currently owns or operates certain retail gasoline outlets where releases of petroleum products have occurred. Federal and state laws and regulations require that contamination caused by such releases at these sites and at formerly owned sites be assessed and remediated to meet the applicable standards. The obligation for Sunoco to remediate this type of contamination varies, depending on the extent of the release and the applicable laws and regulations. A portion of the remediation costs may be recoverable from the reimbursement fund of the applicable state, after any deductible has been met.

In general, each remediation site/issue is evaluated individually based upon information available for the site/issue and no pooling or statistical analysis is used to evaluate an aggregate risk for a group of similar items (e.g., service station sites) in determining the amount of probable loss accrual to be recorded. Sunoco's estimates of environmental remediation costs also frequently involve evaluation of a range of estimates. In many cases, it is difficult to determine that one point in the range of loss estimates is more likely than any other. In these situations, existing accounting guidance requires that the minimum of the range be accrued. Accordingly, the low end of the range often represents the amount of loss which has been recorded.

In addition to the probable and estimable losses which have been recorded, management believes it is reasonably possible (i.e., less than probable but greater than remote) that additional environmental remediation losses will be incurred. At December 31, 2012, the aggregate of the estimated maximum additional reasonably possible losses, which relate to numerous individual sites, totaled approximately $200 million. This estimate of reasonably possible losses associated with environmental remediation is largely based upon analysis during 2012 and continuing into early 2013 of the potential liabilities associated with the establishment of the segregated environmental fund discussed above. It also includes estimates for remediation activities at current logistics and retail assets. This reasonably possible loss estimate in many cases reflects the upper end of the loss ranges which are described above. Such estimates include potentially higher contractor costs for expected remediation activities, the potential need to use more costly or comprehensive remediation methods and longer operating and monitoring periods, among other things.

In summary, total future costs for environmental remediation activities will depend upon, among other things, the identification of any additional sites, the determination of the extent of the contamination at each site, the timing and nature of required remedial actions, the nature of operations at each site, the technology available and needed to meet the various existing legal requirements, the nature and terms of cost-sharing arrangements with other potentially responsible parties, the availability of insurance coverage, the nature and extent of future environmental laws and regulations, inflation rates, terms of consent agreements or remediation permits with regulatory agencies and the determination of Sunoco's liability at the sites, if any, in light of the number, participation level and financial viability of the other parties. The recognition of additional losses, if and when they were to occur, would likely extend over many years. Management believes that none of the current remediation locations, which are in various stages of ongoing remediation, is individually material to Sunoco as its largest accrual for any one Superfund site, operable unit or remediation area was approximately $28 million at December 31, 2012. As a result, Sunoco's exposure to adverse developments with respect to any individual site is not expected to be material. However, if changes in environmental laws or regulations occur or the assumptions used to estimate losses at multiple sites are adjusted, such changes could impact multiple Sunoco facilities, formerly owned facilities and third-party sites at the same time. As a result, from time to time, significant charges against income for environmental remediation may occur; however, management does not believe that any such charges would have a material adverse impact on the Company's consolidated financial position.

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 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.

Air Emissions. Our operations are subject to the federal Clean Air Act and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our processing plants, and also impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities, such as our processing plants and compression facilities, expected to produce air emissions or to result in the increase of existing air emissions, that we obtain and strictly comply with air permits containing various emissions and operational limitations, or that we utilize specific emission control technologies to limit emissions. We will be required to incur capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. In addition, our processing plants, pipelines and compression facilities are subject to increasingly stringent regulations, including regulations that require the installation of control technology or the implementation of work practices to control hazardous air pollutants. Moreover, the Clean Air Act requires an operating permit for major sources of emissions and this requirement applies to some of our facilities. We believe that our operations are in substantial compliance with the federal Clean Air Act and comparable state laws.

The EPA and state agencies are continually proposing and finalizing new rules and regulations that could impact our existing operations and the costs and timing of new infrastructure development. Specifically, EPA has recently finalized new source performance standards (NSPS) for the oil and gas source category. New Subpart OOOO expands the NSPS oil and gas source category to include all segments of the oil and gas industry. It imposes new controls for emissions of volatile organic compounds (VOCs) on well completions, pneumatic devices, compressors, storage vessels and equipment leaks. In addition, EPA has also recently finalized revisions to Subparts HH and HHH that will further reduce emissions of hazardous air pollutants from storage tanks and tri-ethylene glycol dehydrators at major sources. These new regulations will increase our cost of compliance. Petitions have been filed in the court of appeals for review and reconsideration of the new rules, but we cannot predict the outcome of those proceedings.

On October 19, 2010, the EPA adopted new national emission standards for hazardous air pollutants for existing stationary spark ignition reciprocating internal combustion engines that are either located at area sources of hazardous air pollutant emissions or that have a site rating of less than or equal to 500 brake horsepower and are located at major sources of hazardous air pollutant emissions. All engines subject to these “Quad Z” regulations are required to comply by October 19, 2013. Many of our facilities, including our leased compressors are impacted by these new rules. We will incur increased costs to bring engines into compliance with the new emission requirements, but we do not expect these costs to be material.

Clean Water Act. The Clean Water Act and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including hydrocarbon-bearing wastes, into waters of the United States. Pursuant to the Clean Water Act and similar state laws, a NPDES, or state permit, or both, must be obtained to discharge pollutants into federal and state waters. In addition, the Clean Water Act and comparable state laws require that individual permits or coverage under general permits be obtained by subject facilities for discharges of storm water runoff. We believe that we are in substantial compliance with Clean Water Act permitting requirements as well as the conditions imposed thereunder, and that our continued compliance with such existing permit conditions will not have a material adverse effect on our business, financial condition or results of operations.

Spills. Our operations can result in the discharge of regulated substances, including NGLs, crude oil or refined products. The Federal Water Pollution Control Act of 1972, also known as the Clean Water Act, and comparable state laws impose restrictions and strict controls regarding the discharge of regulated substances into state waters or waters of the United States. The Oil Pollution Act subjects owners of covered facilities to strict joint and potentially unlimited liability for removal costs and other consequences of a release of oil, where the release is into navigable waters, along shorelines or in the exclusive economic zone of the United States. Spill prevention control and countermeasure requirements of the Clean Water Act and some state laws require that containment dikes and similar structures be installed to help prevent the impact on navigable waters in the event of a release. The Office of Pipeline Safety of the DOT, the EPA, or various state regulatory agencies, has approved our oil spill emergency response plans, and our management believes we are in substantial compliance with these laws.

In addition, some states maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. Our management believes that compliance with existing permits and compliance with foreseeable new permit requirements will not have a material adverse effect on our results of operations, financial position or expected cash flows.

Endangered Species Act. The Endangered Species Act restricts activities that may affect endangered or threatened species or their habitat. We may operate in areas that are currently designated as a habitat for endangered or threatened species, the discovery of previously unidentified endangered species, or the designation of additional species as endangered or threatened, which could cause us to incur additional costs, to develop habitat conservation plans, to become subject to expansion or operating restrictions, or bans in the affected areas.

Climate Change. On December 15, 2009, the EPA published its findings 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. These findings allow the EPA to adopt and implement regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. Accordingly, the EPA adopted two sets of regulations addressing greenhouse gas emissions under the Clean Air Act. The first limits emissions of greenhouse gases from motor vehicles beginning with the 2012 model year. The EPA has asserted that these final motor vehicle greenhouse gas emission standards trigger Clean Air Act construction and operating permit requirements for stationary sources, commencing when the motor vehicle standards took effect on January 2, 2011. On June 3, 2010, the EPA published its final rule to address the permitting of greenhouse gas emissions from stationary sources under the Prevention of Significant Deterioration ("PSD") and Title V permitting programs. This rule "tailors" these permitting programs to apply to certain stationary sources of greenhouse gas emissions in a multi-step process, with the largest sources first subject to permitting. It is widely expected that facilities required to obtain PSD permits for their greenhouse gas emissions will be required to also reduce those emissions according to “best available control technology” standards for greenhouse gases, which are currently being developed on a case-by-case basis. Any regulatory or permitting obligation that limits emissions of greenhouse gases could require us to incur costs to reduce or sequester emissions of greenhouse gases associated with our operations and also could adversely affect demand for the natural gas and other hydrocarbon products that we transport, process, or otherwise handle in connection with our services.

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 30, 2010, the EPA revised its greenhouse gas reporting rule to include onshore oil and natural gas production, processing, transmission, storage and distribution facilities. Under the new rules, reporting of greenhouse gas emissions from such facilities, including many of our facilities, is required on an annual basis, with reporting that began in 2012 for emissions occurring in 2011.

Various pieces of legislation to reduce emissions of, or to create cap and trade programs for, greenhouse gases have been proposed by the U.S. Congress over the past several years, but no proposal has yet passed. More than one-third 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. The passage of legislation that limits emissions of greenhouse gases from our equipment and operations could require us to incur costs to reduce the greenhouse gas emissions from our own operations, and it could also adversely affect demand for our transportation, storage and processing services.

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 NGLs and 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 products 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.

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

Safety Regulations. Those pipelines through which we transport mixed NGLs (exclusively to other NGL pipelines) are subject to regulation by the DOT, under the HLPSA, relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. The HLPSA requires any entity that owns or operates liquids pipelines to comply with the regulations under the HLPSA, to permit access to and allow copying of records and to submit certain reports and provide other information as required by the Secretary of Transportation. We believe our liquids pipelines are in substantial compliance with applicable HLPSA requirements. The DOT is continually proposing new pipeline safety rules that may impact our businesses and increase our operating costs.

Our interstate, intrastate and certain of our gathering pipelines are also are subject to regulation by the DOT under the NGPSA, which covers natural gas, crude oil, carbon dioxide, NGLs and petroleum products pipelines, and under the Pipeline Safety Improvement Act of 2002, as amended. Pursuant to these authorities, the DOT has established a series of rules that require pipeline operators to develop and implement “integrity management programs” for natural gas pipelines located in areas where the consequences of potential pipeline accidents pose the greatest risk to people and their property. Similar rules are also in place for operators of hazardous liquid pipelines. The DOT's integrity management rules establish requirements relating to the design, installation, testing, construction, operation,

inspection, replacement and management of pipeline facilities. We believe that our pipeline operations are in substantial compliance with applicable NGPSA requirements.
The DOT enacted new control room management regulations as directed by the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006. The rules require operators of hazardous liquids pipelines, gas pipelines and LNG facilities with at least one control room to develop and implement written control room management procedures. We believe we are in substantial compliance with the new rules as of the required compliance date of August 1, 2011.

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On January 3, 2012, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, became effective. Under the new law, the DOT and other federal agencies are required to conduct a number of studies or develop rules over the next two years regarding 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 new law also increases civil penalties for violations, The DOT has already sought comments on potential rules that address many areas of the newly adopted legislation. Any new regulations could impact our businesses and increase our operating costs.

The states administer federal pipeline safety standards under the NGPSA and have the authority to conduct pipeline inspections, to investigate accidents and to oversee compliance and enforcement, safety programs and record maintenance and reporting. Congress, the DOT and individual states may pass additional pipeline safety requirements, but such requirements, if adopted, would not be expected to affect us disproportionately relative to other companies in our industry.

Employees

As of January 31, 2013, we employed 13,847 persons, 2,067 of which are represented by labor unions. We believe that our relations with our employees are satisfactory.

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. In addition, those risk factors discussed in Southern Union's and Sunoco Logistics' Annual Report on Form 10-K should be considered. The risk factors set forth below, and those included in Southern Union's and Sunoco Logistics' Annual Report, 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, crude oil and refined products 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 services;
- the price of natural gas, NGLs, crude oil and refined products;
- the relationship between natural gas, NGL and crude oil 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, transportation and storage and retail marketing companies and other energy providers;
- the level of our operating costs;
- prevailing economic conditions; and
- the level and results 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 revolving credit facility;
- 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 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, 2012, ETE owned 50,226,967 ETP Common Units. 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 2012, 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, 2012, we had approximately $16.22 billion of consolidated debt, excluding the debt of our joint ventures. Our level of indebtedness affects our operations in several ways, including, among other things:

- a significant portion of our and our subsidiaries' 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 and our subsidiaries' existing debt agreements require us and them, as applicable, to meet financial tests that may adversely affect our flexibility in planning for and reacting to changes in our business;
- our and our subsidiaries' ability to obtain additional financing for working capital, capital expenditures, acquisitions and general partnership, corporate or limited liability company purposes, as applicable, 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 by us or our subsidiaries to comply with the various restrictive covenants of our respective debt agreements could negatively impact our ability to incur additional debt, including our ability to utilize the available capacity under our revolving credit facility, and our ability to pay our distributions.

Capital 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 and improvements or repairs to existing facilities that 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.

A significant increase in our indebtedness that is proportionately greater than our issuances of equity could negatively impact our and our subsidiaries' 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.

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. Approximately $2.21 billion of our consolidated debt as of December 31, 2012 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.

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 and from its 60% equity interest in ETP Holdco Corporation, which owns Southern Union and Sunoco, 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 may be unable 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, 2012, ETE and its affiliates held approximately 17% of our outstanding units, with an additional approximate 1% of our outstanding units held by our officers and directors.

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 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 affect our ability to meet our obligations, including any obligations under our debt agreements, and to make distributions to our partners.

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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 pay distributions to our Unitholders and to service our debt 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 funds from our subsidiaries we may not be able to pay distributions to our Unitholders or to pay interest or principal on our debt when due.

We do not have the same flexibility as other types of organizations to accumulate cash, which may limit cash available to service our debt or to repay debt at maturity.

Unlike a corporation, our partnership agreement requires us to distribute, on a quarterly basis, 100% of our Available Cash (as defined in our partnership agreement) 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.

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;”

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- 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.
- 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 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.

Income from our midstream, transportation, terminalling and storage operations is exposed to risks due to fluctuations in the demand for and price of natural gas, NGLs and oil that are beyond our control.

The prices for natural gas, NGLs and oil (including refined petroleum products) reflect market demand that fluctuates with changes in global and U.S. economic conditions and other factors, including:

- the level of domestic natural gas, NGL, and oil production;
- the level of natural gas, NGL, and oil imports and exports, including liquefied natural gas;

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- actions taken by natural gas and oil producing nations;
- instability or other events affecting natural gas and oil producing nations;
- the impact of weather and other events of nature on the demand for natural gas, NGLs and oil;
- the availability of storage, terminal and transportation systems, and refining, processing and treating facilities;
- the price, availability and marketing of competitive fuels;
- the demand for electricity;
- the cost of capital needed to maintain or increase production levels and to construct and expand facilities
- the impact of energy conservation and fuel efficiency efforts; and
- the extent of governmental regulation, taxation, fees and duties.

In the past, the prices of natural gas, NGLs and oil have been extremely volatile, and we expect this volatility to continue. For example, during the year ended December 31, 2012, the NYMEX natural gas settlement price for the prompt month contract ranged from a high of $3.70 per MMBtu to a low of $2.04 per MMBtu. A composite of the Mont Belvieu average NGLs price based upon our average NGLs composition during our year ended December 31, 2012 ranged from a high of approximately $1.23 per gallon to a low of approximately $0.75 per gallon. Oil spot prices at Cushing, Oklahoma during the year ended December 31, 2012 ranged from a high of approximately $109.39 per barrel to a low of approximately $77.72 per barrel.

Any loss of business from existing customers or our inability to attract new customers due to a decline in demand for natural gas, NGLs, or oil could have a material adverse effect on our revenues and results of operations. In addition, significant price fluctuations for natural gas, NGL and oil commodities could materially affect our profitability.

We are affected by competition from other midstream, transportation, terminalling and storage and retail marketing companies.

We experience competition in all of our business segments. With respect to our midstream operations, we compete for both natural gas supplies and customers for our services. Our competitors include major integrated oil companies, interstate and intrastate pipelines and companies that gather, compress, treat, process, transport, store and market natural gas.

Our natural gas and NGL transportation pipelines and storage facilities compete with other interstate and intrastate pipeline companies and storage providers 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 and NGLs also competes with other forms of energy, including electricity, coal, fuel oils and renewable or alternative energy. Competition among fuels and energy supplies is primarily based on price; however, non-price factors, including governmental regulation, environmental impacts, efficiency. ease of use and handling, and the availability of subsidies and tax benefits also affects competitive outcomes.

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

Our crude oil and refined petroleum products pipelines and face significant competition from other pipelines for large volume shipments. These operations also face competition from trucks for incremental and marginal volumes in the areas we served. Further, our crude and refined product terminals compete with terminals owned by integrated petroleum companies, refining and marketing companies, independent terminal companies and distribution companies with marketing and trading operations.

We also face strong competition in the market for the sale of retail gasoline and merchandise. Our competitors include service stations operated by fully integrated major oil companies and other well-recognized national or regional retail outlets, often selling gasoline or merchandise at aggressively competitive prices. The actions of our retail marketing competitors, including the impact of imports, could lead to lower prices or reduced margins for the products we sell, which could have an adverse effect on our business or results of operations.

We may be unable to retain or replace existing midstream, transportation, terminalling and storage customers or volumes due to declining demand or increased competition in oil, natural gas and NGL markets, which would reduce our revenues and limit our future profitability.

The retention or replacement of existing customers and the volume of services that we provide at rates sufficient to maintain or increase current revenues and cash flows depends on a number of factors beyond our control, including the price of, and demand for oil, natural gas, and NGLs in the markets we serve and competition from other service providers.

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A significant portion of our sales of natural gas are to industrial customers and utilities. As a consequence of the volatility of natural gas prices and increased competition in the industry and other factors, industrial customers, utilities and other gas customers are increasingly reluctant to enter into long-term purchase contracts. Many customers purchase natural gas from more than one supplier and have the ability to change suppliers at any time. Some of these customers 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 natural gas sales markets primarily on the basis of price.

We also receive a substantial portion of our revenues by providing natural gas gathering, processing, treating, transportation and storage services. While a substantial portion of our services are sold under long-term contracts for reserved service, we also provide service on an unreserved or short-term basis. Demand for our services may be substantially reduced due to changing market prices. Declining prices may result in lower rates of natural gas production resulting in less use of services; while rising prices may diminish consumer demand and also limit the use of services. In addition, our competitors may attract our customers' business. If demand declines or the effects of competition increases, we may not be able to sustain existing levels of unreserved service or renew or extend long-term contracts as they expire or we may reduce our rates to meet competitive pressures.

Revenue from our NGL transportation systems and refined products storage is also exposed to risks due to fluctuations in demand for transportation and storage service as a result of unfavorable commodity prices, competition from nearby pipelines, and other factors. 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. Reduction in demand for natural gas or NGLs due to unfavorable prices or other factors, however, may result lower rates of production under dedicated contracts and lower demand for our services. In addition, our refined products storage revenues are primarily derived from fixed capacity arrangements between us and our customers, 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.

The volume of crude oil and refined products transported through our oil pipelines and terminal facilities depends on the availability of attractively priced crude oil and refined products in the areas serviced by our assets. A period of sustained price reductions for crude oil or refined products could lead to a decline in drilling activity, production and refining of crude oil, or import levels in these areas. A period of sustained increases in the price of crude oil or refined products supplied from or delivered to any of these areas could materially reduce demand for crude oil or refined products in these areas. In either case, the volumes of crude oil or refined products transported in our oil pipelines and terminal facilities could decline.

The loss of existing customers by our midstream, transportation, terminalling and the storage facilities or a reduction in the volume of the services our customers purchase from us, or our inability to attract new customers and service volumes would negatively affect our revenues, be detrimental to our growth, and adversely affect our results of operations.

Our midstream facilities and transportation pipelines are attached to basins with naturally declining production, which we may not be able to replace with new sources of supply.

In order to maintain or increase throughput levels on our gathering systems 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.

A substantial portion of our assets, including our gathering systems and our processing and treating plants, are connected to natural gas reserves and wells that experience declining production over time. Our gas transportation pipelines are also dependent upon natural gas production in areas served by our gathering systems or in areas served by other gathering systems or transportation pipelines that connect with our transportation pipelines. 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. 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. In addition, we have no control over producers or their production and contracting decisions.

While a substantial portion of our services are provided under long-term contracts for reserved service, we also provide service on an unreserved basis. If the reserves available through the supply basins connected to our gathering, processing, treating, transportation and storage facilities decline and are not replaced by other sources of supply, a decrease in development or production activity could cause a decrease in the volume of unreserved services we provide and decrease in the number and

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volume of our contracts for reserved transportation service over the long run, and in each case, adversely affect our revenues and results of operations.

If we are unable to replace any significant volume declines with additional volumes from other sources, our results of operations and cash flows could be materially and adversely affected.

As a result of our exit from the refining business, we are entirely dependent upon third parties for the supply of refined products such as gasoline and diesel for our retail marketing business.

As a result of our exit from the refining business, we are required to purchase refined products from third party sources, including the joint venture that acquired our Philadelphia refinery. We may also need to contract for new ships, barges, pipelines or terminals which we have not historically used to transport these products to our markets. The inability to acquire refined products and any required transportation services at prices no less favorable than the formerly applicable market-based transfer prices may adversely affect our business and results of operations.

The profitability of certain activities in our natural gas gathering, processing, 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.

For a portion of the natural gas gathered at our systems, 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.

We also 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 revenues and 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.

When we process the gas for a fee under processing fee agreements, we may guarantee recoveries to the producer. 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.

We also receive fees and retain gas in kind from our natural gas transportation and storage customers. Our fuel retention fees and the value of gas that we retain in kind are directly affected by changes in natural gas prices. Increases in natural gas prices tend to increase our fuel retention fees and the value of gas we retain, and decreases in natural gas prices tend to decrease our fuel retention fees and the value of retained gas.

In addition, we receive revenue from our off-gas processing and fractionating system in south Louisiana 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 use of derivative financial instruments could result in material financial losses by us.

From time to time, we have sought to reduce our exposure to fluctuations in 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 forgo the benefits we would otherwise experience if commodity prices or interest rates were to change in our favor.

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The accounting standards regarding hedge accounting are very complex, and even when we engage in hedging transactions that are effective economically (whether to mitigate our exposure to fluctuations in commodity prices, or to balance our exposure to fixed and variable interest rates), these transactions may not be considered effective for accounting purposes. Accordingly, our consolidated financial statements may reflect some volatility due to these hedges, even when there is no underlying economic impact at that point. It is also not always possible for us to engage in a hedging transaction that completely mitigates our exposure to commodity prices. Our consolidated financial statements may reflect a gain or loss arising from an exposure to commodity prices for which we are unable to enter into a completely effective hedge.

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.

Our natural gas and NGL revenues depend on our customer' ability to use our pipelines and third-party pipelines over which we have no control.

Our natural gas transportation, storage and NGL businesses depend, in part, on our customers' ability to obtain access to pipelines to deliver gas to us and receive gas from us. Many of these pipelines are owned by parties not affiliated with us. Any interruption of service on our pipelines or third party pipelines due to testing, line repair, reduced operating pressures, or other causes or adverse change in 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 pipelines and facilities and a corresponding material adverse effect on our transportation and storage revenues. In addition, the rates charged by 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

Shippers using our oil pipelines and terminals are also dependent upon our pipelines and connections to third-party pipelines to receive and deliver crude oil and refined products. Any interruptions or reduction in the capabilities of these pipelines due to testing, line repair, reduced operating pressures, or other causes could result in reduced volumes transported in our pipelines or through our terminals. Similarly, if additional shippers begin transporting volume over interconnecting oil pipelines, the allocations of pipeline capacity to our existing shippers on these interconnecting pipelines could be reduced, which also could reduce volumes transported in its pipelines or through our terminals. Allocation reductions of this nature are not infrequent and are beyond our control. Any such interruptions or allocation reductions that, individually or in the aggregate, are material or continue for a sustained period of time could have a material adverse effect on our results of operations, financial position, or cash flows.

The inability to continue to access lands owned by third parties could adversely affect our ability to operate and our financial results.

Our ability to operate our pipeline systems on certain lands owned by third parties, will depend on our success in maintaining existing rights-of-way and obtaining new rights-of-way on those lands. We are parties to rights-of-way agreements, permits and licenses authorizing land use with numerous parties, including, private land owners, governmental entities, native American tribes, rail carriers, public utilities and others. Our ability to secure extensions of existing agreements, permits and licenses is essential to our continuing business operations, and securing additional rights-of-way will be critical to our ability to pursue expansion projects. We cannot provide any assurance that we will be able to maintain access to existing rights-of-way upon the expiration of the current grants, that all of the rights-of-way will be obtained in a timely fashion or that we will acquire new rights-of-way as needed.

Further, whether we have the power of eminent domain for our pipelines varies from state to state, depending upon the type of pipeline and the laws of the particular state and the ownership of the land to which we seek access. When we exercise eminent down rights or negotiate private agreements cases, we must compensate landowners for the use of their property and, in eminent domain actions, such compensation may be determined by a court. The inability to exercise the power of eminent domain could negatively affect our business if we were to lose the right to use or occupy the property on which our pipelines are located.

In addition, we do not own all of the land on which our oil terminal facilities and our retail service stations are located. We have rental agreements for approximately 28% of the company- or dealer-operated retail service stations where we currently control the real estate and we have rental agreements for certain logistics facilities. As such, we are subject to the possibility of increased costs under rental agreements with landowners, primarily through rental increases and renewals of expired agreements. We are also subject to the risk that such agreements may not be renewed. Additionally, certain facilities and equipment (or parts thereof) used by us are leased from third parties for specific periods. Our inability to renew leases or otherwise maintain the right to utilize such facilities and equipment on acceptable terms, or the increased costs to maintain such rights, could have a material adverse effect on our financial condition, results of operations and cash flows.

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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 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 strategy, we may, from time to time, engage 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 acquisition efforts will be successful or that any acquisition will be completed on terms considered favorable to us.

In addition, we are experiencing increased competition for the assets we purchase or contemplate purchasing. Increased competition for a limited pool of assets could result in us losing to other bidders more often or acquiring assets at higher prices, 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, 2012, our consolidated balance sheet reflected $5.61 billion of goodwill and $1.56 billion 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 then we do.

Furthermore, even if we consummate acquisitions that we believe will be accretive, those acquisitions may in fact adversely affect our results of operations or result in 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.

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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 obtain necessary governmental approvals and contracts with qualified contractors and vendors on acceptable terms;
- we are unable to raise financing for our identified pipeline construction opportunities; or
- we are unable to secure sufficient 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 related 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 and related facilities (or the improvement and repair of existing facilities) involves 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 oil and 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 the area to utilize the newly constructed pipelines. In this regard, we may construct facilities to capture anticipated future growth in oil or 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 and the loss of any of these key producers could adversely affect our financial results.

For the year ended December 31, 2012, EnCana Oil and Gas (USA), Inc. ("Encana"), EnerVest Operating, LLC, and SandRidge Energy Inc. supplied us with approximately 66% of the Southeast Texas System’s natural gas supply. For the year ended December 31, 2012, EOG Resources, Inc., affiliates of Chesapeake Energy Corporation, XTO Energy Inc. (“XTO”) and EnCana Oil and Gas (USA), Inc., supplied us with approximately 58% of the North Texas System’s natural gas supply. For year ended December 31, 2012, Rosetta Resources Operating, LP, SWEPI LP ("Shell") and Anadarko E&P Company LP ("Anadarko") supplied us with approximately 63% of the Rich Eagle Ford Mainline 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.

Our intrastate transportation and storage and interstate transportation and storage operations depend on key customers to transport natural gas through our pipelines and the pipelines of our joint ventures.

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 also extended two natural gas storage contracts 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 will terminate in 2017.

During 2012, Natural Gas Exchange, Inc., Kinder Morgan, XTO and Total Gas & Power North America collectively accounted for approximately 28% of our intrastate transportation and storage revenues.

With respect to our interstate transportation and storage operations we have an agreement with Chesapeake Energy Marketing, Inc. that provides for a 15-year commitment for firm transportation capacity on the Tiger pipeline 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. Additionally, Panhandle has long-term transportation contracts with BG LNG Services and ProLiance, which accounted for 43% of Panhandle's 2012 revenue.

Our joint ventures, FEP and Citrus, also depend on key customers for the transport of natural gas through their pipelines. FEP 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, while Citrus has 10 and 14 year agreements with its top two customers, respectively, which accounted for 59% of its 2012 revenue.

During 2012, Chesapeake Energy Marketing, Inc., EnCana Marketing (USA), Inc. (“EnCana”), Shell Energy North America (US), L.P. and Petrohawk Energy Corporation collectively accounted for 47% of our interstate transportation and storage revenues.

The failure of the major shippers on our and our joint ventures' intrastate and interstate transportation and storage pipelines to fulfill their contractual obligations could have a material adverse effect on our cash flow and results of operations if we or our joint ventures were unable to replace these customers under arrangements that provide similar economic benefits as these existing contracts.

Our interstate pipelines are subject to laws, regulations and policies governing the rates they are allowed to charge for their services, which may prevent us from fully recovering our costs.

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.

We are required to file tariff rates (also known as recourse rates) with FERC that shippers may elect to pay for interstate natural gas transportation services. We may also agree to discount these rates on a not unduly discriminatory basis or negotiate rates with shippers who elect not to pay the recourse rates. We must also file with FERC all negotiated rates that do not conform to our tariff rates and all changes to our tariff or negotiated rates. FERC must approve or accept all rate filings for us to be allowed to charge such rates.

FERC may review existing tariffs rates own initiative or upon receipt of a complaint filed by a third party. FERC may, on a prospective basis, order refunds of amounts collected if it finds the rates to have been shown not to be just and reasonable or to have been unduly discriminatory. FERC has recently exercised this authority with respect to several other pipeline companies, as it had in 2007 with respect to Southwest Gas. If FERC were to initiate a proceeding against us and find that our rates were not just and reasonable or unduly discriminatory, the maximum rates customers could elect to pay us may be reduced and the reduction could have an adverse effect on our revenues and results of operations.

The costs of our interstate pipeline operations may increase and we may not be able to recover all of those costs due to FERC regulation of our rates. If we propose to change our tariff rates, our proposed rates may be challenged by FERC or third parties, and FERC may deny, modify or limit our proposed changes if we are unable to persuade FERC that changes would result in just and reasonable rates that are not unduly discriminatory. We also may be limited by the terms of rate case settlement agreements or negotiated rate agreements with individual customers from seeking future rate increases, or we may be constrained by competitive factors from charging our tariff rates.

To the extent our costs increase in an amount greater than our revenues increase, or there is a lag between our cost increases and our ability to file for, and obtain rate increases, our operating results would be negatively affected. Even if a rate increase is permitted by FERC to become effective, the rate increase may not be adequate. We cannot guarantee that our interstate pipelines will be able to recover all of our costs through existing or future rates.

In 2010, in response to an intervention and protest filed by BG LNG Services (BGLS) regarding its rates with Trunkline LNG applicable to certain LNG expansions, FERC determined that there was no reason at that time to expend FERC's resources on a rate proceeding with respect to Trunkline LNG even though cost and revenue studies provided by the Company to FERC indicated Trunkline LNG's revenues were in excess of its associated cost of service. However, since the current fixed rates expire at the end of 2015 and revert to tariff rate for these LNG expansions as well as the base LNG facilities for which rates were set in 2002, a rate proceeding could be initiated at that time and result in significant revenue reductions if the cost of service remains lower than revenues.

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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 FERC, which was approved by FERC on October 31, 2011. Transwestern is required to file a new general rate case on October 1, 2014. However, shippers that were not parties to the settlement have the right to challenge the lawfulness of tariff rates that have become final and effective. FERC may also investigate such rates absent shipper complaint.

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 FERC and the courts for a number of years. It is currently 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 FERC on a case-by-case basis. Under 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 effectiveness of FERC's policy and the application of that policy remains subject to future challenges, refinement or change by FERC or the courts. 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.

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

In addition to rate oversight, 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 or must 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, policies and interpretations thereof 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 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 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. We may also begin to construct a new facility or provide a new service based on a FERC authorization that is subsequently overturned or modified after review by a court. This could have a material adverse effect on the costs of and revenues of the new facility or service.

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. We cannot predict or control what effect future actions of regulatory agencies may have on its business or its access to the capital markets. Furthermore, the nature and degree of regulation of interstate natural gas pipelines has changed significantly during the past several decades and there is no assurance that further substantial changes will not occur or that existing policies and rules will not be applied in a new or different manner. Should new and more stringent regulatory requirements be imposed, we could be unfavorably impacted and subject to additional costs that could adversely affect its financial condition or results of operations if these costs are not ultimately recovered through rates.

Rate regulation or market conditions may not allow us to recover the full amount of increases in the costs of our crude oil and refined products pipeline operations.

Our common carrier interstate crude oil and refined products pipelines are subject to rate regulation by FERC, which requires that tariff rates for these oil pipelines be just and reasonable and not unduly discriminatory. FERC or interested persons may challenge proposed new or changed rates and authorizes FERC to suspend the effectiveness of such rates for up to seven months and to

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investigate such rates. If, upon completion of an investigation, FERC finds that the new or changed rate is unlawful, it is authorized to require the carrier to refund revenues in excess of the prior tariff during the term of the investigation. FERC also may investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Upon an appropriate showing, a shipper may obtain reparations for damages sustained for a period of up to two years prior to the filing of a complaint.

The primary ratemaking methodology used by FERC to authorize increases in the tariff rates of petroleum pipelines is price indexing. If the rate changes allowed under the indexing methodology are not large enough to fully reflect actual increases to our pipeline costs, our financial condition could be adversely affected. If applying the index methodology results in a rate increase that is substantially in excess of our actual cost increases, or it results in a rate decrease that is substantially less than our pipeline's actual cost decrease, we may be required to reduce our pipeline rates. FERC's ratemaking methodologies may limit our ability to set rates based on its costs or may delay the use of rates that reflect increased costs. In addition, if FERC's indexing methodology changes, the new methodology could materially and adversely affect our financial condition, results of operations or cash flows.

Under the Energy Policy Act adopted in 1992, certain interstate pipeline rates were deemed just and reasonable or “grandfathered.” Revenues are derived from such grandfathered rates on most of our FERC-regulated pipelines. A person challenging a grandfathered rate must, as a threshold matter, establish a substantial change since the date of enactment of the Energy Policy Act, in either the economic circumstances or the nature of the service that formed the basis for the rate. If FERC were to find a substantial change in circumstances, then the existing rates could be subject to detailed review and there is a risk that some rates could be found to be in excess of levels justified by the pipeline's costs. In such event, FERC could order us to reduce pipeline rates prospectively and to pay refunds to shippers.

If FERC's petroleum pipeline ratemaking methodologies procedures changes, the new methodology or procedures could adversely affect our business and results of operations.

Should we violate laws and regulations prohibiting market manipulation, we could be subject to substantial fines and penalties and lose the governmental authorizations needed conduct our businesses.

The Energy Policy Act of 2005 amended the NGA and NGPA to prohibit fraud and manipulation in natural gas markets. FERC subsequently issued a final rule making it unlawful for any entity, in connection with the purchase or sale of natural gas or transportation service subject to FERC's jurisdiction, to defraud, make an untrue statement or omit a material fact or engage in any practice, act or course of business that operates or would operate as a fraud. FERC is authorized to impose civil penalties of up to $1 million per day per violation and grant other relief, such as ordering refunds, or revoking operating authority.

Wholesale sales of petroleum are subject to provisions of the Energy Independence and Security Act of 2007 (“EISA”) and regulations by the FTC. Under the EISA, the FTC issued a rule that prohibits fraudulent or deceptive conduct (including false or misleading statements of material fact) in connection with wholesale purchases or sales of crude oil or refined petroleum products. The FTC rule also bans intentional failures to state a material fact when the omission makes a statement misleading and distorts, or is likely to distort, market conditions for any product covered by the rule. The FTC holds substantial enforcement authority under the EISA, including authority to request that a court impose fines of up to $1 million per day per violation. FERC may also order reparations and suspend tariffs for violations of the ICA in connection with interstate oil pipeline transportation.

Under the Commodity Exchange Act, the CFTC is directed to prevent price manipulations for the commodity and futures markets, including the energy futures markets. Pursuant to the Dodd-Frank Act, the CFTC has adopted anti-market manipulation regulations that prohibit, among other things, fraud and price manipulation in the commodity and futures markets. The CFTC also has statutory authority to assess fines of up to $1,000,000 or triple the monetary gain for violations of its anti-market manipulation regulations

State regulatory measures could adversely affect the business and operations of our midstream and intrastate pipeline and storage 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 service for the interstate services we provide in our intrastate gas pipelines and gas storage are subject to FERC regulation under Section 311 of the NGPA. Our HPL System, East Texas pipeline, Oasis pipeline and ET Fuel System provide such services. Under Section 311, rates charged for transportation and storage must be fair and equitable. 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 FERC determine not to authorize rates equal to or greater than our costs of service, our cash flow would be negatively affected.

Our midstream and intrastate gas and oil transportation pipelines and our intrastate gas storage operations are subject to state regulation. All of the states in which we operate midstream assets, intrastate pipelines or intrastate storage facilities have adopted

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some form of complaint-based regulation, which allow producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to the fairness of rates and terms of access. The states in which we operate have ratable take statutes, which generally require gatherers to take, without undue discrimination, 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. Should a complaint be filed in any of these states or should regulation become more active, our business may be adversely affected.

Our intrastate transportation operations located in Texas are also subject to regulation as gas utilities by the TRRC. Texas gas utilities must publish the rates they charge for transportation and storage services in tariffs filed with the TRRC, although such rates are deemed just and reasonable under Texas law unless challenged in a complaint.

We are subject to other forms of state regulation, including requirements to obtain operating permits, reporting requirements, and safety rules (see description of federal and state pipeline safety regulation below). Violations state laws, regulations, orders and permit conditions can result in the modification, cancellation or suspension of a permit, civil penalties and other relief.

Certain of our assets may become subject to FERC regulation.

The distinction between federally unregulated gathering facilities and FERC-regulated transmission pipelines under the NGA has been the subject of extensive litigation and may be determined by FERC on a case-by-case basis, although FERC has made no determinations as to the status of our facilities. Consequently, the classification and regulation of our gathering facilities could change based on future determinations by FERC or the courts. If our gas gathering operations become subject to FERC jurisdiction, the result may adversely affect the rates we are able to charge and the services we currently provide, and may include the potential for a termination of our gathering agreements with our customers.

We believe that our NGL pipelines do not currently provide interstate service and are not subject to FERC jurisdiction under the ICA and the Energy Policy Act of 1992. We cannot guarantee that the jurisdictional status of our NGL pipelines will remain unchanged. If any of our NGL pipelines became subject to regulation by FERC, pursuant to the ICA, 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 our revenues and results of operations.

We are subject to extensive federal and state pipeline safety regulation, including integrity management requirements, which may adversely affect our costs and operations.

Our pipeline operations are subject to regulation by the DOT, under PHMSA, pursuant to which PHMSA has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. Moreover, 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 million and operating and maintenance costs of $18 million over the course of the next year. For the years ended December 31, 2012, 2011 and 2010, $7 million, $18 million and $13 million, respectively, of capital costs and $17 million, $15 million and $15 million, respectively, of operating and maintenance costs have been incurred for pipeline integrity testing. There can be no assurance as to the amount or timing of future expenditures for pipeline integrity regulation, and actual future expenditures may be different from the amounts we currently anticipate. 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.

Federal pipeline safety regulation is also becoming increasingly stringent and additional laws and regulations are being considered. The recently enacted Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, 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.

On August 13, 2012, PHMSA published rules to update pipeline safety regulations to reflect provisions included in the Pipeline Safety Act of 2011, including increasing maximum civil penalties and changing PHMSA's enforcement process. PHMSA has also published advanced notices of proposed rulemaking to solicit comments on the need for changes to its safety regulations for oil and gas pipelines, including whether to revise the integrity management requirements and add new regulations governing the safety of gathering lines.

Further, additional laws, regulations and policies that may be enacted or adopted in the future or a new interpretation of existing laws and regulations could significantly increase the cost of complying with safety laws and regulations. For example, PHMSA issued an Advisory Bulletin which, among other things, advises pipeline operators that if they are relying on design, construction, inspection, testing or other data to determine the pressures at which their pipelines should operate, the records of that data must be traceable, verifiable and complete. Locating such records and, in the absence of any such records, verifying maximum pressures through physical testing or modifying or replacing facilities to meet the demands of such pressures, could significantly increase our costs or result in reductions of allowable operating pressures, which would reduce available pipeline capacity. 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.

States are largely preempted by federal law from regulating pipeline safety for interstate lines, but most are certified by the DOT to assume responsibility for enforcing federal intrastate pipeline regulations and inspection of intrastate pipelines.

In addition, we are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act, or OSHA, and comparable state statutes, the purposes of which are to protect the health and safety of workers, both generally and within the pipeline industry. In addition, the OSHA hazard communication standard, the Environmental Protection Agency, or EPA, community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that such information be provided to employees, state and local government authorities and citizens. We are also subject to OSHA Process Safety Management regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. These regulations apply to any process which involves a chemical at or above the specified thresholds or any process which involves flammable liquid or gas, pressurized tanks, caverns and wells in excess of 10,000 pounds at various locations. Flammable liquids stored in atmospheric tanks below their normal boiling points without the benefit of chilling or refrigeration are exempt.

Should we violate federal or state health and safety laws and regulations, we could be subject to substantial criminal, civil and administrative penalties and other relief, as well as potential liabilities to third parties.

Our natural gas distribution operations subject us to risks that could have a material adverse effect on our business, results of operations, cash flows and financial condition.

On December 17, 2012, Southern Union entered into definitive purchase and sale agreements with subsidiaries of the Laclede Group, Inc. to sell the assets of its Missouri Gas Energy and New England Gas Company Divisions. Until the transaction is consummated, we will be subject to various risks relating to our natural gas distribution operations, including the following:

- our ability to achieve timely and effective rate relief from state regulators;
- the impact of fluctuations in natural gas prices;
- the inability to recover from customers certain assets recorded on our balance sheet;
- adverse weather conditions;
- operational risks, including accidents, the breakdown or failure of equipment or processes, the failure of suppliers' processing facilities to perform at expected levels of capacity or efficiency and the collision of equipment with facilities; and
- catastrophic events, including explosions, fires, earthquakes, floods, landslides, tornadoes, lightning or other similar events.

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

Our 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 U.S. Environmental Protection Agency (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

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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 current or former 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 pipelines or 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. Although we have established financial reserves for our estimated environmental remediation liabilities, additional contamination or conditions may be discovered, resulting in increased remediation liabilities. Environmental laws also authorize government agencies, in some circumstance, to seek compensation for natural resource damages as an adjunct to remediation programs. If such natural resource damages claims are brought against us, our liability associated with any such sites could substantially increase. Accordingly, we cannot assure you that our current reserves are adequate to cover all future liabilities, even for currently known contamination.

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 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.

Product liability claims and litigation could adversely affect our business and results of operations.

Product liability is a significant commercial risk. Substantial damage awards have been made in certain jurisdictions against manufacturers and resellers based upon claims for injuries caused by the use of or exposure to various products. There can be no assurance that product liability claims against us would not have a material adverse effect on our business or results of operations.

Along with other refiners, manufacturers and sellers of gasoline, Sunoco is a defendant in numerous lawsuits that allege methyl tertiary butyl ether (“MTBE”) contamination in groundwater. Plaintiffs, who include water purveyors and municipalities responsible for supplying drinking water and private well owners, are seeking compensatory damages (and in some cases injunctive relief, punitive damages and attorneys' fees) for claims relating to the alleged manufacture and distribution of a defective product (MTBE-containing gasoline) that contaminates groundwater, and general allegations of product liability, nuisance, trespass, negligence, violation of environmental laws and deceptive business practices. There has been insufficient information developed about the plaintiffs' legal theories or the facts that would be relevant to an analysis of the ultimate liability to Sunoco. These allegations or other product liability claims against Sunoco could have a material adverse effect on our business or results of 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 April 17, 2012, the EPA issued final rules that would establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the 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 by January 2015, 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. These rules will require us to modify certain of our operations, including the possible installation of new equipment. Compliance with such rules will be required within three years of their effective date, 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, NGLs, crude oil and refined products that we transport, store or otherwise handle.
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 has recently adopted 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 another which regulates emissions of greenhouse gases from certain large stationary sources, effective January 2, 2011. In November 2011, the EPA also adopted rules requiring companies with facilities that emit over 25,000 metric tons or more of carbon dioxide to report their greenhouse gas emissions to the EPA by September 30, 2012, a requirement with which we timely complied.
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 may be reduced over time 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, NGLs, crude oil and refined products. 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 fuels 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.
The adoption of the Dodd-Frank Act 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, resulting in our operations becoming more volatile and our cash flows less predictable.
Congress has adopted the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"), a comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The legislation was signed into law by President Obama on July 21, 2010 and requires the U.S. Commodity Futures Trading Commission ("CFTC"), the SEC and other regulators to promulgate rules and regulations implementing the new legislation. While certain regulations have been promulgated and are already in effect, the rulemaking and implementation process is still ongoing, and we cannot yet predict the ultimate effect of the rules and regulations on our business.
The Dodd-Frank Act expanded the types of entities that are required to register with the CFTC and the SEC as a result of their activities in the derivatives markets or otherwise become specifically qualified to enter into derivatives contracts. We will be required to assess our activities in the derivatives markets, and to monitor such activities on an

ongoing basis, to ascertain and to identify any potential change in our regulatory status.

Reporting and recordkeeping requirements also could significantly increase operating costs and expose us to penalties for non-compliance. Certain CFTC recordkeeping requirements became effective on October 14, 2010, and additional recordkeeping requirements will be phased in through April 2013. Beginning on December 31, 2012, certain CFTC reporting rules became effective, and additional reporting requirements will be phased in through April 2013. These additional recordkeeping and reporting requirements may require additional compliance resources. Added public transparency as a result of the reporting rules may also have a negative effect on market liquidity which could also negatively impact commodity prices and our ability to hedge.

The CFTC has also issued regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. The CFTC’s position limits rules were to become effective on October 12, 2012, but a United States District Court vacated and remanded the position limits rules to the CFTC. The CFTC has appealed that ruling and it is uncertain at this time whether, when, and to what extent the CFTC's position limits rules will become effective.

The new regulations may also require us to comply with certain margin requirements for our over-the counter derivative contracts with certain CFTC- or SEC-registered entities that could require us to enter into credit support documentation and/or post significant amounts of cash collateral, which could adversely affect our liquidity and ability to use derivatives to hedge our commercial price risk; however, the proposed margin rules are not yet final and therefore 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 also requires that certain derivative instruments be centrally cleared and executed through an exchange or other approved trading platform. Mandatory exchange trading and clearing requirements could result in increased costs in the form of additional margin requirements imposed by clearing organizations. On December 13, 2012, the CFTC published final rules regarding mandatory clearing of certain interest rate swaps and certain index credit default swaps and setting compliance dates for different categories of market participants, the earliest of which is March 11, 2013. The CFTC has not yet proposed any rules requiring the clearing of any other classes of swaps, including physical commodity swaps. Although there may be an exception to the mandatory exchange trading and clearing requirement that applies to our trading activities, we must obtain approval from the board of directors of our General Partner and make certain filings in order to rely on this exception. In addition, mandatory clearing requirements applicable to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging.

Rules promulgated under the Dodd-Frank Act further defined forwards as well as instances where forwards may become swaps. Because the CFTC rules, interpretations, no-action letters, and case law are still developing, it is possible that some arrangements that previously qualified as forwards or energy service contracts may fall in the regulatory category of swaps or options. In addition, the CFTC's rules applicable to trade options may further impose burdens on our ability to conduct our traditional hedging operations and could become subject to CFTC investigations in the future.

The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through restrictions on the types of collateral we are required to post), 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 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. Finally, if we fail to comply with applicable laws, rules or regulations, we may be subject to fines, cease-and-desist orders, civil and criminal penalties or other sanctions.

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.

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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. Some of our facilities are subject to standards and procedures required by the Chemical Facility Anti-Terrorism Standards. We believe we are in compliance with all material requirements; however, such compliance may not prevent a terrorist attack from causing material damage to our facilities or pipelines. Any such 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 30 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;
- 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.

We are subject to risks resulting from the moratorium in 2010 on and the resulting increased costs of offshore deepwater drilling.

The United States Department of Interior (the "DOI") implemented a six-month moratorium on offshore drilling in water deeper than 500 feet in response to the Macondo accident and oil spill in the U.S. Gulf of Mexico. The offshore drilling moratorium was implemented to permit the DOI to review the safety protocols and procedures used by offshore drilling companies, which review will enable the DOI to recommend enhanced safety and training needs for offshore drilling companies. The moratorium was lifted in October 2010. The United States Bureau of Ocean Energy Management and the Bureau of Safety and Environmental Enforcement (formerly the Bureau of Ocean Energy Management, Regulation and Enforcement) have enacted enhanced regulatory mandates with additional regulatory mandates expected. The new regulatory requirements will increase the cost of offshore drilling and production operations. The increased regulations and cost of drilling operations could result in decreased drilling activity in the

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areas serviced by Southern Union. Furthermore, the imposed moratorium did result in some offshore drilling companies relocating their offshore drilling operations for currently indeterminable periods of time to regions outside of the United States. Business decisions to not drill in the areas serviced by Southern Union resulting from the increased regulations and costs could result in a reduction in the future development and production of natural gas reserves in the vicinity of Southern Union's facilities, which could adversely affect our business, financial condition, results of operations and cash flows.

Our business is subject to federal, state and local laws and regulations that govern the product quality specifications of the petroleum products that we store and transport.

The petroleum products that we store and transport through Sunoco Logistics' operations are sold by our customers for consumption into the public market. Various federal, state and local agencies have the authority to prescribe specific product quality specifications to commodities sold into the public market. Changes in product quality specifications could reduce our throughput volume, require us to incur additional handling costs or require the expenditure of significant capital. In addition, different product specifications for different markets impact the fungibility of products transported and stored in our pipeline systems and terminal facilities and could require the construction of additional storage to segregate products with different specifications. We may be unable to recover these costs through increased revenues.

In addition, our butane blending services are reliant upon gasoline vapor pressure specifications. Significant changes in such specifications could reduce butane blending opportunities, which would affect our ability to market our butane blending services licenses.

Our business could be affected adversely by union disputes and strikes or work stoppages by Southern Union's, Sunoco Logistics' and Sunoco's unionized employees.

As of December 31, 2012, approximately 37%, 45% and 7% of Southern Union's, Sunoco Logistics' and Sunoco's workforce, respectively, are covered by a number of collective bargaining agreements with various terms and dates of expirations. There can be no assurances that Southern Union or Sunoco will not experience a work stoppage in the future as a result of labor disagreements. Any work stoppage could, depending on the affected operations and the length of the work stoppage, have a material adverse effect on our business, financial position, results of operations or cash flows.

Governmental regulations and policies, particularly in the areas of taxation, energy and the environment, have a significant impact on our retail marketing business.

Federally mandated standards for use of renewable biofuels, such as ethanol and biodiesel in the production of refined products, are transforming traditional gasoline and diesel markets in North America. These regulatory mandates present production and logistical challenges for both the petroleum refining and ethanol industries, and may require us to incur additional capital expenditures or expenses particularly in our retail marketing business. We may have to enter into arrangements with other parties to meet our obligations to use advanced biofuels, with potentially uncertain supplies of these new fuels. If we are unable to obtain or maintain sufficient quantities of ethanol to support our blending needs, our sale of ethanol blended gasoline could be interrupted or suspended which could result in lower profits. There also will be compliance costs related to these regulations. We may experience a decrease in demand for refined petroleum products due to new federal requirements for increased fleet mileage per gallon or due to replacement of refined petroleum products by renewable fuels. In addition, tax incentives and other subsidies making renewable fuels more competitive with refined petroleum products may reduce refined petroleum product margins and the ability of refined petroleum products to compete with renewable fuels. A structural expansion of production capacity for such renewable biofuels could lead to significant increases in the overall production, and available supply, of gasoline and diesel in markets that we supply. In addition, a significant shift by consumers to more fuel-efficient vehicles or alternative fuel vehicles (such as ethanol or wider adoption of gas/electric hybrid vehicles), or an increase in vehicle fuel economy, whether as a result of technological advances by manufacturers, legislation mandating or encouraging higher fuel economy or the use of alternative fuel, or otherwise, also could lead to a decrease in demand, and reduced margins, for the refined petroleum products that we market and sell.

It is possible that any, or a combination, of these occurrences could have a material adverse effect on Sunoco's business or results of operations.

We have outsourced various functions related to our retail marketing business to third-party service providers, which decreases our control over the performance of these functions. Disruptions or delays of our third-party outsourcing partners could result in increased costs, or may adversely affect service levels. Fraudulent activity or misuse of proprietary data involving our outsourcing partners could expose us to additional liability.

Sunoco has previously outsourced various functions related to our retail marketing business to third parties and expects to continue this practice with other functions in the future.

While outsourcing arrangements may lower our cost of operations, they also reduce our direct control over the services rendered. It is uncertain what effect such diminished control will have on the quality or quantity of products delivered or services rendered, on our ability to quickly respond to changing market conditions, or on our ability to ensure compliance with all applicable domestic and foreign laws and regulations. We believe that we conduct appropriate due diligence before entering into agreements with our outsourcing partners. We rely on our outsourcing partners to provide services on a timely and effective basis. Although we continuously monitor the performance of these third parties and maintain contingency plans in case they are unable to perform as agreed, we do not ultimately control the performance of our outsourcing partners. Much of our outsourcing takes place in developing countries and, as a result, may be subject to geopolitical uncertainty. The failure of one or more of our third-party outsourcing partners to provide the expected services on a timely basis at the prices we expect, or as required by contract, due to events such as regional economic, business, environmental or political events, information technology system failures, or military actions, could result in significant disruptions and costs to our operations, which could materially adversely affect our business, financial condition, operating results and cash flow.

Our failure to generate significant cost savings from these outsourcing initiatives could adversely affect our profitability and weaken Sunoco's competitive position. Additionally, if the implementation of our outsourcing initiatives is disruptive to our retail marketing business, we could experience transaction errors, processing inefficiencies, and the loss of sales and customers, which could cause our business and results of operations to suffer.

As a result of these outsourcing initiatives, more third parties are involved in processing our retail marketing information and data. Breaches of security measures or the accidental loss, inadvertent disclosure or unapproved dissemination of proprietary information or sensitive or confidential data about our retail marketing business or our clients, including the potential loss or disclosure of such information or data as a result of fraud or other forms of deception, could expose us to a risk of loss or misuse of this information, result in litigation and potential liability for us, lead to reputational damage to the Sunoco brand, increase our compliance costs, or otherwise harm our business.

Our operations could be disrupted if our information systems fail, causing increased expenses and loss of sales.

Our business is highly dependent on financial, accounting and other data processing systems and other communications and information systems, including our enterprise resource planning tools. We process a large number of transactions on a daily basis and rely upon the proper functioning of computer systems. If a key system was to fail or experience unscheduled downtime for any reason, even if only for a short period, our operations and financial results could be affected adversely. Our systems could be damaged or interrupted by a security breach, fire, flood, power loss, telecommunications failure or similar event. We have a formal disaster recovery plan in place, but this plan may not entirely prevent delays or other complications that could arise from an information systems failure. Our business interruption insurance may not compensate us adequately for losses that may occur.

Security breaches and other disruptions could compromise our information and expose us to liability, which would cause its business and reputation to suffer.

In the ordinary course of our business, we collect and store sensitive data, including intellectual property, our proprietary business information and that of our customers, suppliers and business partners, and personally identifiable information of our employees, in our data centers and on our networks. The secure processing, maintenance and transmission of this information is critical to our operations and business strategy. Despite our security measures, our information technology and infrastructure may be vulnerable to attacks by hackers or breached due to employee error, malfeasance or other disruptions. Any such breach could compromise our networks and the information stored there could be accessed, publicly disclosed, lost or stolen. Any such access, disclosure or other loss of information could result in legal claims or proceedings, liability under laws that protect the privacy of personal information, regulatory penalties for divulging shipper information, disruption of our operations, damage to our reputation, and loss of confidence in our products and services, which could adversely affect our business.

The costs of providing pension and other postretirement health care benefits and related funding requirements are subject to changes in pension fund values, changing demographics and fluctuating actuarial assumptions and may have a material adverse effect on our financial results. In addition, the passage of the Health Care Reform Act in 2010 could significantly increase the cost of providing health care benefits for employees.

Certain of our subsidiaries provide pension plan and other postretirement healthcare benefits to certain of their employees. The costs of providing pension and other postretirement health care benefits and related funding requirements are subject to changes in pension and other postretirement fund values, changing demographics and fluctuating actuarial assumptions that may have a material adverse effect on the Partnership's future consolidated financial results. In addition, the passage of the Health Care Reform Act of 2010 could significantly increase the cost of health care benefits for our employees. While certain of the costs incurred in providing such pension and other postretirement healthcare benefits are recovered through the rates charged by the Partnership's regulated businesses, the Partnership's subsidiaries may not recover all of the costs and those rates are generally not immediately responsive to current market conditions or funding requirements. Additionally, if the current cost recovery mechanisms are changed or eliminated, the impact of these benefits on operating results could significantly increase.

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, from time to time, members of the U.S. Congress propose and consider substantive changes to the existing U.S. federal income tax laws that affect the tax treatment of 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 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.

The tax treatment of Sunoco Logistics depends on its status as a partnership for federal income tax purposes, as well as its not being subject to a material amount of entity-level taxation by individual states. If the IRS were to treat Sunoco Logistics as a corporation for federal income tax purposes or if it were to 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 its unitholders.

The anticipated after-tax economic benefit of our investment in the common units of Sunoco Logistics depends largely on Sunoco Logistics being treated as a partnership for federal income tax purposes. Sunoco Logistics has not requested, and does not plan to request, a ruling from the IRS on this matter. The IRS may adopt positions that differ from the ones Sunoco Logistics has taken. A successful IRS contest of the federal income tax positions Sunoco Logistics takes may impact adversely the market for its common units, and the costs of any IRS contest will reduce Sunoco Logistics' cash available for distribution to its unitholders. If Sunoco Logistics were to be treated as a corporation for federal income tax purposes, it would pay federal income tax at the corporate tax rate, and likely would pay state income tax at varying rates. Distributions to its unitholders generally would be subject to tax again as corporate distributions. Treatment of Sunoco Logistics as a corporation would result in a material reduction in its

anticipated cash flow and after-tax return to its unitholders. Current law may change so as to cause Sunoco Logistics to be treated as a corporation for federal income tax purposes or to otherwise subject it to a material amount of entity-level taxation. 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 states were to impose a tax on Sunoco Logistics, the cash available for distribution to its unitholders would be reduced.
As discussed above, the present federal income tax treatment of publicly traded partnerships, including Sunoco Logistics, or our investment in its common units, may be modified by administrative, legislative or judicial interpretation at any time. Any

modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. Moreover, any such modification could make it more difficult or impossible for Sunoco Logistics to meet the exception which allows publicly traded partnerships that generate qualifying income to be treated as partnerships (rather than corporations) for U.S. federal income tax purposes, affect or cause Sunoco Logistics to change its business activities, or affect the tax consequences of our investment in Sunoco Logistics' common units. Any such changes could negatively impact the value of our investment in Sunoco Logistics' common units.

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 that 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 have subsidiaries that will be treated as corporations for federal income tax purposes and subject to corporate-level income taxes.

Even though we (as a partnership for U.S. federal income tax purposes) are not subject to U.S. federal income tax, some of our operations are currently, and our acquisition of Sunoco and the Holdco restructuring resulted in an increase in the proportion of our operations that are conducted through subsidiaries that are organized as corporations for U.S. federal income tax purposes. The taxable income, if any, of subsidiaries that are treated as corporations for U.S. federal income tax purposes, is subject to corporate-level U.S. federal income taxes, which may reduce the cash available for distribution to us and, in turn, to our unitholders. If the IRS or other state or local jurisdictions were to successfully assert that these corporations have more tax liability than we anticipate or legislation was enacted that increased the corporate tax rate, the cash available for distribution could be further reduced. The income tax return filings positions taken by these corporate subsidiaries require significant judgment, use of estimates, and the interpretation and application of complex tax laws. Significant judgment is also required in assessing the timing and amounts of deductible and taxable items. Despite our belief that the income tax return positions taken by these subsidiaries are fully supportable, certain positions may be successfully challenged by the IRS, state or local jurisdictions.

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.

Because we cannot match transferors and transferees of Common Units and because of other reasons, we will adopt depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our Unitholders. It also could affect the timing of these tax benefits or the amount of gain from the sale of Common Units and could have a negative impact on the value of our Common Units or result in audit adjustments to tax returns of our Unitholders. Moreover, because we have subsidiaries that are organized as C corporations for federal income tax purposes which own 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.

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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 (and our Unitholders could receive two Schedules K-1 if relief was not available, as described below) 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 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. The IRS has recently announced a publicly traded partnership technical termination relief program whereby, if a publicly traded partnership that technically terminated requests publicly traded partnership technical termination relief and such relief is granted by the IRS, among other things, the partnership will only have to provide one Schedule K-1 to unitholders for the year notwithstanding two partnership tax years.

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 many states, most of which 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.

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.

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

Sunoco, along with other refiners, manufacturers and sellers of gasoline, is a defendant in lawsuits alleging MTBE contamination of groundwater. The plaintiffs typically include water purveyors and municipalities responsible for supplying drinking water and

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governmental authorities. The plaintiffs are asserting primarily product liability claims and additional claims including nuisance, trespass, negligence, violation of environmental laws and deceptive business practices. The plaintiffs in all of the cases are seeking to recover compensatory damages, and in some cases, injunctive relief , punitive damages and attorneys' fees.

As of December 31, 2012, Sunoco was a defendant in two lawsuits involving one state and Puerto Rico. These cases are venued in a multidistrict proceeding in a New York federal court. Both cases assert natural resource damage claims. In addition, Sunoco has received notice from another state that it intends to file an MTBE lawsuit in the near future asserting natural resource damage claims.

Discovery is proceeding in these cases. There has been insufficient information developed about the plaintiffs' legal theories or the facts in the natural resource damage claims that would be relevant to an analysis of the ultimate liability of Sunoco in these matters; however, it is reasonably possible that a loss may be realized. Management believes that the MBTE cases could have a significant impact on results of operations for any future period, but does not believe that the cases will have a material adverse effect on its consolidated financial position.

For a description of legal proceedings, see Note 10 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
	High	Low	Distribution [1]
Fiscal Year 2012			
Fourth Quarter	$45.00	$40.19	$0.89375
Third Quarter	46.00	41.35	0.89375
Second Quarter	51.00	41.15	0.89375
First Quarter	50.12	45.75	0.89375
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

(1) 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 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 25, 2013, there were approximately 552,000 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 currently owned by HHI, a subsidiary of Holdco. 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.

In conjunction with the Sunoco merger, we amended our partnership agreement to create the Class F Units. The number of Class F Units issued was determined at the closing of the Sunoco merger and equaled 90,706,000, which includes 40,000,000 Class F Units issued in exchange for cash contributed by Sunoco to us immediately prior to or concurrent with the closing of the Sunoco merger. The Class F Units generally do not have any voting rights. The Class F Units issued to Sunoco in connection with the Sunoco merger are entitled to aggregate cash distributions equal to 35% of the total amount of cash that is generated by us and our subsidiaries (other than Holdco) and available for distribution, up to a maximum of $3.75 per Class F Unit per year.

As of December 31, 2012, our General Partner owned an approximate 0.9% general partner interest in us and the holders of Common Units, Class E and Class F Units collectively owned a 99.1% 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.

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Cash Distribution Policy

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

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

- Less the amount of cash reserves that are necessary or appropriate in the reasonable discretion of the General Partner to
  - provide for the proper conduct of our business;
  - comply with applicable law 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 enables 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

The terms of our partnership agreement require that we make cash distributions with respect to each calendar quarter within 45 days following the end of each calendar quarter. We are required to make distributions of Available Cash from operating surplus for any quarter in the following manner:

- First, 100% to all Common Unitholders, Class E Unitholders, Class F 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");
- Second, 100% to all Common Unitholders, Class E Unitholders, Class F Unitholders and the general partner, in accordance with their respective percentage interests, until each Common Unit has received $0.275 per unit for such quarter (the "first target distribution");
- Third, (i) to the general partner in accordance with its percentage interest, (ii) 13% to the holders of the IDRs, pro rata, and (iii) to all Common Unitholders, Class E Unitholders and Class F Unitholders, pro rata, a percentage equal to 100% less the percentages applicable to the general partner and holders of the IDRs, until each Common Unit has received $0.3175 per unit for such quarter (the "second target distribution");
- Fourth, (i) to the general partner in accordance with its percentage interest, (ii) 23% to the holders of the IDRs, pro rata, and (iii) to all Common Unitholders, Class E Unitholders and Class F Unitholders, pro rata, a percentage equal to 100% less the percentages applicable to the general partner and holders of the IDRs, until each Common Unit has received $0.4125 per unit for such quarter (the "third target distribution"); and
- Fifth, thereafter, (i) to the general partner in accordance with its percentage interest, (ii) 48% to the holder of the IDRs, pro rata, and (iii) to all Common Unitholders, Class E Unitholders and Class F Unitholders, pro rata, a percentage equal to 100% less the percentages applicable to the general partner and holders of the IDRs.

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

Notwithstanding the foregoing, the distributions on each Class E unit may not exceed $1.41 per year and distributions on each Class F unit may not exceed $3.75 per year. In addition, the distributions to the holders of the incentive distribution rights will not exceed the amount the holders of the incentive distributions rights would otherwise receive if the available cash for distribution were reduced to the extent it constitutes amounts previously distributed with respect to the Class F units.

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 7 to our consolidated financial statements. All distributions were made from Available Cash from our operating surplus.

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Recent Sales of Unregistered Securities
None.
Issuer Purchases of Equity Securities

None.

ITEM 6. SELECTED FINANCIAL DATA
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 millions.
In accordance with GAAP, we have accounted for the Holdco Transaction, whereby ETP obtained control of Southern Union, as a reorganization of entities under common control. Accordingly, ETP's consolidated financial statements have been retrospectively adjusted to reflect consolidation of Southern Union into ETP beginning March 26, 2012 (the date ETE acquired Southern Union). In December 2012, Southern Union entered into a purchase and sale agreement with the Laclede Entities, pursuant to which Laclede Missouri has agreed to acquire the assets of Missouri Gas Energy division and Laclede Massachusetts has agreed to acquire the assets of the New England Gas Company division. The results of continuing operations of the distribution operations have been reclassified to income from discontinued operations.
These changes only impacted interim periods in 2012, and no prior annual amounts have been adjusted for the Holdco Transaction.
In October 2012, we sold ETC Canyon Pipeline, LLC ("Canyon") for approximately $207 million. The results of continuing operations of Canyon have been reclassified to loss from discontinued operations and the prior year amounts have been adjusted to present Canyon's operations as discontinued operations.

	Years Ended December 31,				
	2012	2011	2010	2009	2008
Statement of Operations Data:					
Total revenues	$15,702	$6,799	$5,843	$5,378	$9,237
Operating income	1,394	1,247	1,065	1,134	1,138
Income from continuing operations	1,757	700	623	797	886
Basic income from continuing operations per limited partner unit	4.93	1.12	1.23	2.56	3.88
Diluted income from continuing operations per limited partner unit	4.91	1.12	1.23	2.56	3.88
Cash distributions per unit	3.58	3.58	3.58	3.58	3.55
Balance Sheet Data (at period end):					
Total assets	43,230	15,519	12,150	11,735	10,627
Long-term debt, less current maturities	15,442	7,388	6,405	6,177	5,619
Total equity	17,332	6,350	4,743	4,600	3,743
Other Financial Data:					
Capital expenditures:					
Maintenance (accrual basis)	313	134	99	103	141
Growth (accrual basis)	2,771	1,375	1,290	530	1,922
Cash (received in) paid for acquisitions	(531)	1,972	178	(30)	85

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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:
  - natural gas midstream and intrastate transportation and storage through Southern Union and La Grange Acquisition, L.P., which conducts business under the assumed name of ETC OLP; and
  - interstate natural gas transportation and storage through ET Interstate and Southern Union. ET Interstate is the parent company of Transwestern, ETC FEP, ETC Tiger and CrossCountry. Southern Union is the parent company of Panhandle, which provides transportation and storage services through the Panhandle, Trunkline and Sea Robin transmission systems.
- NGL transportation, storage and fractionation services primarily through Lone Star.
- Refined product and crude oil operations, including the following:
  - refined product and crude oil transportation through Sunoco Logistics; and
  - retail marketing of gasoline and middle distillates through Sunoco.
- Other operations, including the following:
  - natural gas compression services through ETC Compression;
  - a limited partner interest in AmeriGas;
  - natural gas distribution operations through Southern Union; and
  - an approximate 30% non-operating interest in a refining joint venture.

Recent Developments

Sunoco Merger

On October 5, 2012, Sam Acquisition Corporation, a Pennsylvania corporation and a wholly owned subsidiary of ETP, completed its merger with Sunoco. Under the terms of the merger agreement, Sunoco shareholders received a total of approximately 55 million ETP Common Units and approximately $2.6 billion in cash.

Sunoco generates cash flow from a portfolio of retail outlets for the sale of gasoline and middle distillates in the east coast, midwest and southeast areas of the United States. Prior to October 5, 2012, Sunoco also owned a 2% general partner interest, 100% of the IDRs, and 32% of the outstanding common units of Sunoco Logistics. As discussed below, on October 5, 2012, Sunoco's interests in Sunoco Logistics were transferred to the Partnership.

Sunoco Logistics is a publicly traded limited partnership that owns and operates a logistics business consisting of a geographically diverse portfolio of complementary pipeline, terminalling and crude oil acquisition and marketing assets. The refined products pipelines business consists of refined products pipelines located in the northeast, midwest and southwest United States, and equity interests in refined products pipelines. The crude oil pipeline business consists of crude oil pipelines located principally in Oklahoma and Texas. The terminal facilities business consists of refined products and crude oil terminal capacity at the Nederland Terminal on the Gulf Coast of Texas and capacity at the Eagle Point terminal on the banks of the Delaware River in New Jersey. The crude oil acquisition and marketing business, principally conducted in Oklahoma and Texas, involves the acquisition and marketing of crude oil and consists of crude oil transport trucks and crude oil truck unloading facilities.

ETP incurred merger related costs related to the Sunoco merger of $28 million during the year ended December 31, 2012.

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Holdco Transaction

Immediately following the closing of the Sunoco Merger, ETE contributed its interest in Southern Union into ETP Holdco Corporation (“Holdco”), an ETP-controlled entity, in exchange for a 60% equity interest in Holdco. In conjunction with ETE's contribution, ETP contributed its interest in Sunoco to Holdco and retained a 40% equity interest in Holdco. Pursuant to a stockholders agreement between ETE and ETP, ETP controls Holdco. Consequently, ETP consolidated Holdco (including Sunoco and Southern Union) in its financial statements subsequent to consummation of the Holdco Transaction. Prior to the contribution of Sunoco to Holdco, Sunoco contributed $2.0 billion of cash and its interests in Sunoco Logistics to ETP in exchange for 90,706,000 Class F Units representing limited partner interests in ETP ("Class F Units"). The Class F Units are entitled to 35% of the quarterly cash distribution generated by ETP and its subsidiaries other than Holdco, subject to a maximum cash distribution of $3.75 per Class F Unit per year, which is the current level.

Under the terms of the Holdco transaction agreement, ETE agreed to relinquish its right to $210 million of incentive distributions from ETP that ETE would otherwise be entitled to receive over 12 consecutive quarters beginning with the distribution paid on November 14, 2012.

Sale of Distribution Operations

In December 2012, Southern Union entered into a purchase and sale agreement with the Laclede Entities, pursuant to which Laclede Missouri has agreed to acquire the assets of the Missouri Gas Energy division and Laclede Massachusetts has agreed to acquire the assets of the New England Gas Company division. Total consideration for the acquisitions will be $1.04 billion, subject to customary closing adjustments, less the assumption of approximately $19 million of debt. For the period from March 26, 2012 to December 31, 2012, the distribution operations have been reclassified to discontinued operations in the consolidated statements of operations. The assets and liabilities of the disposal group have been reclassified and reported as assets and liabilities held for sale as of December 31, 2012.

SUGS Contribution

On February 27, 2013, Southern Union entered into a definitive contribution agreement to contribute to Regency all of the issued and outstanding membership interest in Southern Union Gathering Company, LLC, and its subsidiaries, including SUGS. The consideration to be paid by Regency in connection with this transaction will consist of (i) the issuance of 31,372,419 Regency common units to Southern Union, (ii) the issuance of 6,274,483 Regency Class F units to Southern Union, (iii) the distribution of $570 million in cash to Southern Union, and (iv) the payment of $30 million in cash to a subsidiary of ETP. The Regency Class F units will have the same rights, terms and conditions as the Regency common units, except that Southern Union will not receive distributions on the Regency Class F units for the first eight consecutive quarters following the closing, and the Regency Class F units will thereafter automatically convert into Regency common units on a one-for-one basis. Upon the closing of the transaction, ETE will agree to forego all distributions with respect to its IDRs on the Regency common units issued in the transaction for the first eight consecutive quarters following the closing. The transaction is expected to close in the second quarter of 2013.

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 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, the Citrus Acquisition, the Sunoco merger, the Holdco Transaction 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 distributable cash flow to our Partnership for years to come.

Our principal operations as of December 31, 2012 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 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 and storage – The majority of our interstate transportation and storage 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. 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.

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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 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.

- Investment in Sunoco Logistics – Revenues are generated by charging tariffs for transporting refined products, crude oil and other hydrocarbons through our pipelines as well as by charging fees for terminalling services for refined products, crude oil and other hydrocarbons at our facilities. Revenues are also generated by acquiring and marketing crude oil and refined products. Generally, crude oil and refined products purchases are entered into in contemplation of or simultaneously with corresponding sale transactions involving physical deliveries, which enables us to secure a profit on the transaction at the time of purchase.
- Retail marketing – Revenue is principally generated from the sale of gasoline and middle distillates and the operation of convenience stores in 25 states, primarily on the east coast and in the midwest region of the United States. These stores supplement sales of fuel products with a broad mix of merchandise such as groceries, fast foods, beverages and tobacco products.

Trends and Outlook

Having completed several major strategic transactions since 2011 to expand our midstream service capabilities and to geographically diversify our asset platform, our focus is currently on the full integration and optimization of our diversified asset portfolio to enhance unitholder value. We expect to simplify our organization during 2013 and 2014 and possibly beyond. In order to take advantage of numerous asset optimization opportunities, we may consider potential transactions among us and our subsidiaries and/or affiliates. We also expect to consider sales or transfers of non-core assets or businesses. As in the past, we will also continue to evaluate growth projects and acquisitions as such opportunities may be identified in the future, and we intend to continue to maintain sufficient liquidity to allow us to fund such potential growth projects and acquisitions.

With respect to industry trends, we expect to see continued high natural gas storage relative to historical levels. We anticipate overall consumption of natural gas in the United States will be stable during 2013. 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 are also subject to risk from not renewing long-term fee-based contracts in areas of declining supply. We expect these volumes to continue to trend downward in areas where we have assets connected to dry gas given the outlook on natural gas prices and production in 2013.

We 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 2013 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 2013.

We expect to see continued opportunities related to wet or rich natural gas from shale formations, as well as continued demand for NGL related services, including storage, fractionation and exportation. In addition, we anticipate significant demand for crude transportation to the Gulf Coast markets. Consequently, these expectations will shape our strategic transactions and growth projects in the near term.

Results of Operations

We report Segment Adjusted EBITDA as a measure of segment performance. We define Segment Adjusted EBITDA 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, loss on extinguishment of debt, gain on deconsolidation 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 unconsolidated affiliates based on the Partnership's proportionate ownership and amounts for less than wholly owned subsidiaries based on 100% of the subsidiaries' results of operations. Previously, amounts for less than wholly owned subsidiaries were reflected in Segment Adjusted EBITDA based on the Partnership's proportionate ownership, such that the measure was reduced for amounts attributable to noncontrolling interests. During the three months ended December 31, 2012, management changed its definition of Segment Adjusted EBITDA to reflect amounts for less than wholly owned subsidiaries based on 100% of the subsidiaries' results of operations. Management believes that the revised segment performance measure more closely reflects the presentation of less than wholly owned subsidiaries within the Partnership's consolidated financial statements. For periods prior to the three months ended December 31, 2012, only the NGL transportation and services segment included a less than wholly owned subsidiary. Based on this change in our definition of Segment Adjusted EBITDA, we have recast the presentation of our segment results for 2011 to be consistent with the current year presentation. This change did not impact 2010, because the noncontrolling interest did not exist prior to the LDH Acquisition and formation of Lone Star.

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, 2012 Compared to the Year Ended December 31, 2011 (tabular dollar amounts are expressed in millions)

In accordance with GAAP, we have accounted for the Holdco Transaction, whereby ETP obtained control of Southern Union, as a reorganization of entities under common control. Accordingly, ETP's consolidated financial statements have been retrospectively adjusted to reflect consolidation of Southern Union into ETP beginning March 26, 2012 (the date ETE acquired Southern Union). This change only impacted interim periods in 2012, and no prior annual amounts have been adjusted.

Consolidated Results

	Years ended December 31,		
	2012	2011	Change
Segment Adjusted EBITDA			
Intrastate transportation and storage	$601	$667	$(66)
Interstate transportation and storage	1,013	373	640
Midstream	438	389	49
NGL transportation and services	209	127	82
Investment in Sunoco Logistics	219	—	219
Retail Marketing	109	—	109
All other	155	225	(70)
Total Segment Adjusted EBITDA	2,744	1,781	963
Depreciation and amortization	(656)	(405)	(251)
Interest expense, net of interest capitalized	(665)	(474)	(191)
Gain on deconsolidation of Propane Business	1,057	—	1,057
Losses on non-hedged interest rate derivatives	(4)	(77)	73
Non-cash compensation expense	(42)	(37)	(5)
Unrealized losses on commodity risk management activities	(9)	(11)	2
LIFO valuation reserve	(75)	—	(75)
Loss on extinguishment of debt	(115)	—	(115)
Impairment of investments in affiliates	—	(5)	5
Adjusted EBITDA attributable to discontinued operations	(99)	(23)	(76)
Adjusted EBITDA related to unconsolidated affiliates	(480)	(56)	(424)
Equity in earnings of unconsolidated affiliates	142	26	116
Other, net	22	—	22
Income from continuing operations before income tax expense	1,820	719	1,101
Income tax expense	(63)	(19)	(44)
Income from continuing operations	1,757	700	1,057
Income from discontinued operations	(109)	(3)	(106)
Net income	$1,648	$697	$951

See the detailed discussion of Segment Adjusted EBITDA below.

Depreciation and Amortization. Depreciation and amortization increased primarily due to:

- depreciation and amortization related to Southern Union of $179 million from March 26, 2012 through December 31, 2012;
- depreciation and amortization related to Sunoco Logistics and Sunoco of $63 million and $32 million, respectively, from October 5, 2012 through December 31, 2012; and
- additional depreciation and amortization recorded from assets placed in service in 2011 and 2012;

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These increases in depreciation and amortization were offset by the impact from the January 2012 deconsolidation of the Propane Business, for which our consolidated results reflected $4 million and $82 million in depreciation and amortization for the years ended December 31, 2012 and 2011, respectively.

Interest Expense. Interest expense increased primarily due to:

- interest expense recorded by Southern Union of $130 million from March 26, 2012 through December 31, 2012;
- interest expense related to Sunoco Logistics and Sunoco of $14 million and $9 million, respectively, from October 5, 2012 through December 31, 2012; and
- incremental interest expense due to the issuance of $1.5 billion of senior notes in May 2011 to fund the LDH acquisition and the issuance of $2.0 billion of senior notes in January 2012 to fund the Citrus Acquisition; offset by
- a reduction of several series of our higher coupon notes that were repurchased in the tender offers completed in January 2012; and
- an increase in capitalized interest related to our growth projects.

Gain on Deconsolidation of Propane Business. A gain on deconsolidation was recognized as a result of the contribution of our Propane Business to AmeriGas in January 2012.

Losses on Non-Hedged Interest Rate Derivatives. Losses on non-hedged interest rate derivatives decreased due to the recognition of losses in 2011 resulting from significant forward rate decreases during 2011.

LIFO Valuation Reserve. A LIFO valuation reserve was recorded for the inventory associated with Sunoco's retail marketing operations as a result of commodity price changes subsequent to the inventory being recorded at fair value in connection with purchase accounting.

Loss on Extinguishment of Debt. A loss on extinguishment of debt was recognized in January 2012 in connection with our tender offers in which we repurchased approximately $750 million in aggregate principal amount of Senior Notes.

Adjusted EBITDA Related to Unconsolidated Affiliates and Equity in Earnings of Unconsolidated Affiliates. Amounts reflected for 2012 primarily include our proportionate share of such amounts related to AmeriGas, Citrus and FEP. The 2011 amounts primarily represented our proportionate share of such amounts for FEP only. Such amounts were included in calculating Segment Adjusted EBITDA and net income.

Adjusted EBITDA Attributable to Discontinued Operations. Amounts reflect the operations of Canyon, which was sold in October 2012, and, for the period from March 26, 2012 to December 31, 2012, Southern Union's distribution operations.

Other, net. Other, net increased in 2012 primarily due to Southern Union's recognition of a net curtailment gain of $15 million related to its postretirement benefit plans.

Income Tax Expense. Income tax expense increased primarily due to the acquisitions of Southern Union and Sunoco, both of which are taxable corporations.

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Supplemental Pro Forma Financial Information
The following unaudited pro forma consolidated financial information of ETP has been prepared in accordance with Article 11 of Regulation S-X and reflects the pro forma impacts of the Sunoco Merger and Holdco Transaction for the year ended December 31, 2012 and 2011, giving effect that each occurred on January 1, 2011. This unaudited pro forma financial information is provided to supplement the discussion and analysis of the historical financial information and should be read in conjunction with such historical financial information. This unaudited pro forma information is for illustrative purposes only and is not necessarily indicative of the financial results that would have occurred if the Sunoco Merger and Holdco Transaction had been consummated on January 1, 2011.

The following table presents the pro forma financial information for the year ended December 31, 2012.

	ETP Historical	Propane Transaction (a)	Sunoco Historical (b)	Southern Union Historical (c)	Holdco Pro Forma Adjustments (d)	Pro Forma
REVENUES	$15,702	$(93)	$35,258	$443	$(12,174)	$39,136
COSTS AND EXPENSES:						
Cost of products sold - natural gas operations	13,166	(80)	33,142	302	(11,193)	35,337
Depreciation and amortization	656	(4)	168	49	76	945
Selling, general and administrative	486	(1)	459	11	(119)	836
Impairment charges	—		124		(22)	102
Total costs and expenses	14,308	(85)	33,893	362	(11,258)	37,220
OPERATING INCOME	1,394	(8)	1,365	81	(916)	1,916
OTHER INCOME (EXPENSE):						
Interest expense, net of interest capitalized	(665)	(24)	(123)	(50)	2	(860)
Equity in earnings of affiliates	142	19	41	16	5	223
Gain on deconsolidation of Propane Business	1,057	(1,057)	—	—	—	—
Gain on formation of Philadelphia Energy Solutions	—	—	1,144	—	(1,144)	—
Loss on extinguishment of debt	(115)	115	—	—	—	—
Gains (losses) on non-hedged interest rate derivatives	(4)	—	—	—	—	(4)
Impairment charges	—		—	—		—
Other, net	11	2	118	(2)	(2)	127
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE (BENEFIT)	1,820	(953)	2,545	45	(2,055)	1,402
Income tax expense (benefit)	63	—	956	12	(871)	160
INCOME FROM CONTINUING OPERATIONS	$1,757	$(953)	$1,589	$33	$(1,184)	$1,242

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The following table presents the pro forma financial information for the year ended December 31, 2011.

	ETP Historical	Propane Transaction (a)	Sunoco Historical (b)	Southern Union Historical (c)	Holdco Pro Forma Adjustments (d)	Pro Forma
REVENUES	$6,799	$(1,427)	$45,328	$1,997	$(16,528)	$36,169
COSTS AND EXPENSES:						
Cost of products sold - natural gas operations	4,935	(1,174)	44,119	1,338	(16,677)	32,541
Depreciation and amortization	405	(78)	335	204	(2)	864
Selling, general and administrative	212	(47)	598	42	(56)	749
Impairment charges	—	—	2,629	—	(2,569)	60
Total costs and expenses	5,552	(1,299)	47,681	1,584	(19,304)	34,214
OPERATING INCOME	1,247	(128)	(2,353)	413	2,776	1,955
OTHER INCOME (EXPENSE):						
Interest expense, net of interest capitalized	(474)	(40)	(172)	(218)	29	(875)
Equity in earnings of affiliates	26	148	15	99	(158)	130
Gains (losses) on non-hedged interest rate derivatives	(77)	—	—	—	—	(77)
Impairment charges	(5)	—	—	—	—	(5)
Other, net	2	2	44	—	(2)	46
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE (BENEFIT)	719	(18)	(2,466)	294	2,645	1,174
Income tax expense (benefit)	19	(4)	(1,063)	80	1,070	102
INCOME FROM CONTINUING OPERATIONS	$700	$(14)	$(1,403)	$214	$1,575	$1,072

(a) Propane Transaction adjustments reflect the following:

- The adjustments reflect the deconsolidation of ETP's propane operations in connection with the Propane Transaction.
- The adjustments reflect the pro forma impacts from the consideration received in connection with the Propane Transaction, including ETP's receipt of AmeriGas common units and ETP's use of cash proceeds from the transaction to redeem long-term debt.
- The 2012 adjustments include the elimination of (i) the gain recognized by ETP in connection with the deconsolidation of the Propane Business and (ii) ETP's loss on extinguishment of debt recognized in connection with the use of proceeds to redeem of long-term debt.

(b) Sunoco historical amounts in 2012 include only the period from January 1, 2012 through September 30, 2012.
(c) Southern Union historical amounts in 2012 include only the period from January 1, 2012 through March 25, 2012.
(d) Substantially all of the Holdco pro forma adjustments relate to Sunoco's exit from its Northeast refining operations and formation of the PES joint venture, except for the following:

- The adjustment to depreciation and amortization reflects incremental amounts for estimated fair values recorded in purchase accounting related to Sunoco and Southern Union.
-

The adjustment to selling, general and administrative expenses includes the elimination of merger-related costs incurred, because such costs would not have a continuing impact on results of operations.

- The adjustment to interest expense includes incremental amortization of fair value adjustments to debt recorded in purchase accounting.
- The adjustment to equity in earnings of affiliates reflects the reversal of amounts related to Citrus Corp. recorded in Southern Union's historical income statements.

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- The adjustment to income tax expense includes the pro forma impact resulting from the pro forma adjustments to pre-tax income of Sunoco and Southern Union.

Supplemental Information on Unconsolidated Affiliates

The following table presents equity in earnings of unconsolidated affiliates, the proportionate share of unconsolidated affiliates' interest, depreciation, amortization, non-cash compensation expense, loss on debt extinguishment and taxes by unconsolidated affiliate, Adjusted EBITDA related to unconsolidated affiliates and distributions received from affiliates for the years ended December 31, 2012 and 2011:

	Years Ended December 31,		
	2012	2011	Change
Equity in earnings of unconsolidated affiliates:			
AmeriGas	$ (4)	$ —	$ (4)
Citrus	65	—	65
FEP	55	24	31
Other	26	2	24
Total equity in earnings of unconsolidated affiliates	$ 142	$ 26	$ 116
Proportionate share of interest, depreciation, amortization, non-cash compensation expense, loss on debt extinguishment and taxes:			
AmeriGas	$ 143	$ —	$ 143
Citrus	163	—	163
FEP	22	29	(7)
Other	10	1	9
Total proportionate share of interest, depreciation, amortization, non-cash compensation expense, loss on debt extinguishment and taxes	$ 338	$ 30	$ 308
Adjusted EBITDA related to unconsolidated affiliates:			
AmeriGas	$ 139	$ —	$ 139
Citrus	228	—	228
FEP	77	53	24
Other	36	3	33
Total Adjusted EBITDA related to unconsolidated affiliates	$ 480	$ 56	$ 424
Distributions received from unconsolidated affiliates:			
AmeriGas	$ 94	$ —	$ 94
Citrus	88	—	88
FEP	70	46	24
Other	10	5	5
Total distributions received from unconsolidated affiliates	$ 262	$ 51	$ 211

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.

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- 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.

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 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,		
	2012	2011	Change
Natural gas MMBtu/d — transported	9,849,900	11,295,084	(1,445,184)
Revenues	$2,191	$2,674	$(483)
Cost of products sold	1,394	1,774	(380)
Gross margin	797	900	(103)
Unrealized losses on commodity risk management activities	19	9	10
Operating expenses, excluding non-cash compensation expense	(173)	(191)	18
Selling, general and administrative, excluding non-cash compensation expense	(43)	(54)	11
Adjusted EBITDA related to unconsolidated affiliates	1	3	(2)
Segment Adjusted EBITDA	$601	$667	$(66)

Volumes. We experienced a decrease in transport volumes in 2012 due to a less favorable natural gas price environment, the cessation of certain long-term contracts, and lower basis differentials primarily between the West and East Texas hubs. The average spot price at the Houston Ship Channel for 2012 declined to $2.70/MMBtu from $3.94/MMBtu for 2011, while the average basis differential between West Texas and the Houston Ship Channel decreased from $0.035/MMBtu in 2011 to $0.019/MMBtu in 2012.

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

	Years Ended December 31,		
	2012	2011	Change
Transportation fees	$550	$599	$(49)
Natural gas sales and other	95	107	(12)
Retained fuel revenues	79	130	(51)
Storage margin, including fees	73	64	9
Total gross margin	$797	$900	$(103)

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Our 2012 margin decreased as compared to 2011 due to the net impact of the following factors:

- Transport fees decreased primarily due to a decrease in transported volumes as unfavorable market conditions continued and the cessation of certain long-term transportation contracts;
- 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 $28 million in 2012 compared to $36 million in 2011. The decrease of $8 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 primarily due to a decline of $30 million in margin where we utilize third party processing, offset by increased margin of $13 million from wellhead purchases in the Eagle Ford Shale that were sold to end users on our HPL system and increased margin of $4 million from system optimization and other operational 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. Excluding derivatives related to storage, unrealized gains of $13 million were recorded in 2012 as compared to unrealized losses of $21 million in 2011; and

- 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 $51 million due to less retained volumes and a $37 million decline in the average of natural gas spot prices.

Storage margin was comprised of the following:

	Years Ended December 31,		
	2012	2011	Change
Withdrawals from storage natural gas inventory (MMBtu)	12,887,906	24,517,008	(11,629,102)
Realized margin on natural gas inventory transactions	$75	$19	$56
Fair value inventory adjustments	27	(52)	79
Unrealized gains (losses) on derivatives	(59)	63	(122)
Margin recognized on natural gas inventory, including related derivatives	43	30	13
Revenues from fee-based storage	31	35	(4)
Other costs	(1)	(1)	—
Total storage margin	$73	$64	$9

The increase in our storage margin was principally driven by gains on settled derivatives which offset a decline in margin on the physical sale of storage gas due to a decrease in volumes withdrawn from our Bammel storage facility. Additionally, we experienced a decline in fee-based storage revenue due to the cessation of 4.5 Bcf of fixed fee storage contracts in 2011.

Unrealized (Gains) 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. For 2012, unrealized losses on derivatives of $46 million were offset by fair value adjustments to storage gas inventory of $27 million. For 2011, unrealized losses reflected fair value adjustments to storage gas inventory of $52 million, offset by gains on derivatives of $42 million.

Operating Expenses, Excluding Non-Cash Compensation Expense. Intrastate transportation and storage operating expenses decreased primarily due to a decrease in natural gas consumed for compression of $16 million due to lower spot prices and a decrease in ad valorem taxes of $3 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 employee-related costs and allocated overhead expenses.

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Interstate Transportation and Storage

	Years Ended December 31,		
	2012	2011	Change
Natural gas transported (MMBtu/d)			
ETP Legacy Assets	2,978,410	2,800,655	177,755
Southern Union transportation and storage	3,832,929	—	3,832,929
Natural gas sold (MMBtu/d)	18,065	22,405	(4,340)
Revenues	$1,109	$447	$662
Operating expenses, excluding non-cash compensation, amortization and accretion expenses	(244)	(93)	(151)
Selling, general and administrative, excluding non-cash compensation, amortization and accretion expenses	(156)	(34)	(122)
Adjusted EBITDA related to unconsolidated affiliates	304	53	251
Segment Adjusted EBITDA	$1,013	$373	$640

Volumes. Transported volumes increased significantly due to the consolidation of Southern Union's transportation and storage businesses beginning March 26, 2012. Transported volumes for the Transwestern and Tiger pipelines increased by 177,755 MMBtu/d primarily due to the recent Tiger pipeline expansion.

Revenues. Southern Union's transportation and storage business recognized revenues of $592 million from March 26, 2012 through December 31, 2012. Tiger pipeline revenues also increased approximately $91 million primarily due to incremental reservation fees related to the Tiger pipeline expansion. These increases were offset slightly by a decrease in operational gas sales on the Transwestern pipeline.

Operating Expenses, Excluding Non-Cash Compensation, Amortization and Accretion Expense. Substantially all of the increase was due to the consolidation of Southern Union's transportation and storage business beginning March 26, 2012.

Selling, General and Administrative, Excluding Non-Cash Compensation, Amortization and Accretion Expense. Substantially all of the increase was due to the consolidation of Southern Union's transportation and storage business beginning March 26, 2012.

Adjusted EBITDA Related to Unconsolidated Affiliates. Adjusted EBITDA related to unconsolidated affiliates increased primarily due to our acquisition of a 50% interest in Citrus which contributed $228 million during the year ended December 31, 2012. In addition, Adjusted EBITDA related to FEP increased $24 million primarily due to an increase in demand fees as a result of incremental volume commitments in our shippers' take or pay contracts.

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Midstream

	Years Ended December 31,		
	2012	2011	Change
Gathered Volumes (MMBtu/d)			
ETP Legacy Assets	2,364,133	2,020,126	344,007
Southern Union gathering and processing	510,061	—	510,061
NGLs produced (Bbls/d)			
ETP Legacy Assets	79,640	54,246	25,394
Southern Union gathering and processing	41,163	—	41,163
Equity NGLs produced (Bbls/d)			
ETP Legacy Assets	17,314	16,385	929
Southern Union gathering and processing	7,437	—	7,437
Revenues	$3,084	$2,543	$541
Cost of products sold	2,432	2,072	360
Gross margin	652	471	181
Unrealized (gains) losses on commodity risk management activities	2	(3)	5
Operating expenses, excluding non-cash compensation expense	(151)	(83)	(68)
Selling, general and administrative, excluding non-cash compensation expense	(73)	(19)	(54)
Adjusted EBITDA related to unconsolidated affiliates	(7)	—	(7)
Adjusted EBITDA attributable to discontinued operations	15	23	(8)
Segment Adjusted EBITDA	$438	$389	$49

Volumes. NGL production increased primarily due to increased inlet volumes as a result of more production by our customers in the Eagle Ford Shale area and increased capacity from recent completed projects. The increase in equity NGL production was primarily due to the higher production partially offset by a higher concentration of volumes billed under fee-based contracts in 2012 as compared to 2011. Additionally, in conjunction with the Holdco Transaction, Southern Union's gathering and processing operations were retrospectively consolidated into our midstream segment beginning March 26, 2012. For the period from March 26, 2012 to December 31, 2012, NGL production averaged 41,163 Bbls/d for Southern Union's gathering and processing operations.

Gross Margin. The components of our midstream segment gross margin were as follows:

	Years Ended December 31,		
	2012	2011	Change
Gathering and processing fee-based revenues	$339	$253	$86
Non fee-based contracts and processing	335	234	101
Other	(22)	(16)	(6)
Total gross margin	$652	$471	$181

Midstream gross margin increased between the periods due to the net impact of the following:

- Gathering and processing fee-based revenues. Increased volumes from production in the Eagle Ford Shale resulted in increased fee-based revenues of $70 million in 2012 as compared to 2011, partially offset by declines in the Fort Worth Basin that affected our North Texas system resulting in a $5 million decline from 2012 to 2011. Additionally, Southern Union's gathering and processing segment contributed $20 million of fee-based revenue during March 26, 2012 through December 31, 2012.
- Non fee-based contracts and processing margin. We recorded $125 million of incremental non-fee based revenue in connection with the consolidation of Southern Union's gathering and processing business from March 26, 2012 through December 31, 2012. Excluding these incremental revenues from Southern Union's gathering and processing business,

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our non fee-based gross margins decreased $24 million primarily due to lower NGL prices. The composite NGL price for 2012 was $0.96 per gallon as compared to $1.30 per gallon in 2011.

- Other midstream gross margin. We recorded derivative losses of $2 million in 2012 associated with our marketing activities compared to derivative gains of $4 million in 2011 resulting in a decline of $6 million from 2012 compared to 2011. For the years ended December 31, 2012 and 2011, other midstream margin included $28 million and $36 million, respectively, of fees charged by our intrastate transportation systems. These fees were recognized as income by our intrastate transportation and storage segment and have no effect on our consolidated results of operations.

Unrealized (Gains) Losses on Commodity Risk Management Activities. Our midstream segment recorded unrealized losses of $2 million in 2012 associated with our marketing activities compared to unrealized gains of $3 million in 2011 mainly due to lower notional volumes hedged compared to the prior year.

Operating Expenses, Excluding Non-Cash Compensation Expense. Midstream operating expenses increased primarily due to the consolidation of Southern Union's gathering and processing operations effective March 26, 2012. In addition, growth in the Eagle Ford Shale region resulted in $6 million of additional operating expenses.

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation Expense. Midstream selling, general and administrative expenses increased primarily due to consolidation of Southern Union's gathering and processing operations effective March 26, 2012. In addition, additional assets placed into service in the Eagle Ford Shale also caused a slight increase. For the periods presented, selling, general and administrative expenses increased $38 million due to consolidation of Southern Union's gathering and processing operations. Increases related to new assets in the Eagle Ford Shale were higher due to employee costs of $7 million, an increase in insurance costs of $2 million, an increase in professional fees of $1 million, an increase in information technology costs of $3 million and an increase in office expenses of $2 million.

NGL Transportation and Services

	Years Ended December 31,		
	2012	2011	Change
NGL transportation volumes (Bbls/d)	172,569	132,862	39,707
NGL fractionation volumes (Bbls/d)	17,754	16,475	1,279
Revenues	$650	$397	$253
Cost of products sold	361	218	143
Gross margin	289	179	110
Operating expenses, excluding non-cash compensation expense	(60)	(39)	(21)
Selling, general and administrative, excluding non-cash compensation expense	(20)	(13)	(7)
Segment Adjusted EBITDA	$209	$127	$82

Our NGL Transportation and Services segment reflected the results from Lone Star, which was formed in 2011 and acquired all of the membership interests in LDH on May 2, 2011, as well as multiple other wholly-owned or joint venture pipelines that have recently become operational.

Volumes. The volumes reflected above for the year ended December 31, 2012 represent average daily volumes for the period from May 2, 2011 to December 31, 2012. NGL transportation volumes increased for the year ended December 31, 2012 as compared to the same period in the prior year primarily due to an increase in volumes transported on our wholly-owned and joint venture NGL pipelines originating from our La Grange and Chisholm processing plants as a result of more production from the Eagle Ford area. Average daily fractionated volumes increased for the year ended December 31, 2012 as compared to the year ended December 31, 2011 at our Geismar fractionation complex in Louisiana due to less refinery downtime in 2012 as compared to the comparable prior year period.

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

	Years Ended December 31		
	2012	2011	Change
Storage revenues	$129	$93	36
Transportation revenues	80	33	47
Processing and fractionation revenues	81	53	28
Other revenues	(1)	—	(1)
Total gross margin	$289	$179	$110

For the year ended December 31, 2012 compared to the same period in the prior year, NGL transportation and services segment gross margin reflected twelve months of activity compared to only eight months of activity in 2011. Additionally, gross margin for the year ended December 31, 2012 was impacted by the following items which did not have a comparable impact in the prior period:

- Incurred a $2 million lower-of-cost or market write down on inventory held as of June 30, 2012 in our storage facility and pipelines;
- Hurricane Isaac resulted in an approximate $4 million decrease to our processing and fractionation margin; and
- The Freedom Pipeline and Liberty Pipeline, which were placed in service in 2012, and Justice Pipeline, which began interim service in 2012, contributed $12 million in the aggregate for the year ended December, 31, 2012.

The Lone Star West Texas Gateway pipeline and the Lone Star Fractionator I were both placed in service in December 2012; therefore, the gross margin impact in 2012 was not significant.

Operating Expenses, Excluding Non-Cash Compensation Expense. Operating expenses increased due to operations of Lone Star for twelve months in 2012 compared to eight months in 2011. The Lone Star West Texas Gateway pipeline and the Lone Star Fractionator I were both placed in service in December 2012; therefore, the operating expense impact in 2012 was not significant.

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation Expense. NGL Transportation and Storage selling, general and administrative expenses increased due to operations of Lone Star for twelve months in 2012 compared to eight months in 2011.

Investment in Sunoco Logistics

	Years Ended December 31		
	2012	2011	Change
Revenue	$3,194	$—	$3,194
Cost of products sold	2,843	—	2,843
Gross margin	351	—	351
Unrealized losses on commodity risk management activities	(15)	—	(15)
Operating expenses, excluding non-cash compensation expense	(95)	—	(95)
Selling, general and administrative, excluding non-cash compensation expense	(32)	—	(32)
Adjusted EBITDA related to unconsolidated affiliates	10	—	10
Segment Adjusted EBITDA	$219	$—	$219

We obtained control of Sunoco Logistics on October 5, 2012 in connection with our acquisition of Sunoco; therefore, no comparative results were reflected in our financial statements.

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Retail Marketing

	Years Ended December 31		
	2012	2011	Change
Total retail gasoline outlets, end of period	4,988	—	4,988
Total company-operated outlets, end of period	437	—	437
Gasoline and diesel throughput per company-operated site (gallons/month)	198,000	—	198,000
Revenue	$5,926	$—	$5,926
Cost of products sold	5,757	—	5,757
Gross margin	169	—	169
Operating expenses, excluding non-cash compensation expense	(119)	—	(119)
Selling, general and administrative, excluding non-cash compensation expense	(17)	—	(17)
LIFO valuation reserve	75	—	75
Adjusted EBITDA related to unconsolidated affiliates	1	—	1
Segment Adjusted EBITDA	$109	$—	$109

We acquired our retail marketing segment on October 5, 2012 in connection with our acquisition of Sunoco; therefore, no comparative results were reflected in our financial statements.

All Other

	Years Ended December 31		
	2012	2011	Change
Revenue	$407	$1,656	$(1,249)
Cost of products sold	320	1,016	(696)
Gross margin	87	640	(553)
Unrealized losses on commodity risk management activities	3	4	(1)
Operating expenses, excluding non-cash compensation expense	(57)	(355)	298
Selling, general and administrative, excluding non-cash compensation expense	(116)	(54)	(62)
Adjusted EBITDA related to unconsolidated affiliates	166	—	166
Adjusted EBITDA attributable to discontinued operations	84	—	84
Elimination	(12)	(10)	(2)
Segment Adjusted EBITDA	$155	$225	$(70)

For 2011, our “All Other” segment included our retail propane and other retail propane business, as well as certain other businesses. As a result, substantially all of the activity for 2011 in the “All Other” segment is attributable to the retail propane and other retail propane related business. In January 2012, we contributed the propane business to AmeriGas. In 2012 amounts reflected in our other segment primarily include:

- Our retail propane and other retail propane related operations prior to our contribution of those operations to AmeriGas Partners, L.P. ("AmeriGas") in January 2012. Our investment in AmeriGas was reflected in the other segment subsequent to that transaction;
- Southern Union's local distribution operations beginning March 26, 2012;
- Our natural gas compression operations; and,
- Sunoco's approximate 30% non-operating interest in Philadelphia Energy Solutions ("PES"), a joint venture with The Carlyle Group, L.P. ("The Carlyle Group"), which owns a refinery in Philadelphia.

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

	Years ended December 31,		
	2011	2010	Change
Segment Adjusted EBITDA			
Intrastate natural gas transportation and storage	$667	$716	$(49)
Interstate natural gas transportation and storage	373	220	153
Midstream	389	329	60
NGL transportation and services	127	—	127
All other	225	276	(51)
Total Segment Adjusted EBITDA	1,781	1,541	240
Depreciation and amortization	(405)	(317)	(88)
Interest expense, net of interest capitalized	(474)	(413)	(61)
Gains on non-hedged interest rate derivatives	(77)	5	(82)
Non-cash compensation expense	(37)	(28)	(9)
Unrealized gains (losses) on commodity risk management activities	(11)	(78)	67
Impairment of investments in affiliates	(5)	(53)	48
Adjusted EBITDA attributable to discontinued operations	(23)	(19)	(4)
Adjusted EBITDA related to unconsolidated affiliates	(56)	(35)	(21)
Equity in earnings of unconsolidated affiliates	26	12	14
Other, net	—	24	(24)
Income from continuing operations before income tax expense	$719	$639	$80
Income tax expense	$(19)	$(16)	$(3)
Income from continuing operations	$700	$623	$77
Income from discontinued operations	$(3)	$(6)	$3
Net income	$697	$617	$80

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 million for our interstate transportation and storage segment primarily due to the Tiger pipeline which was placed in service in December 2010. Depreciation and amortization increased by $25 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 $33 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 $13 million and $16 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.

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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.

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 $53 million to reduce the carrying value of our interest to its estimated fair value.

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.

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Supplemental Information on Unconsolidated Affiliates

The following table presents equity in earnings of unconsolidated affiliates, the proportionate share of unconsolidated affiliates' interest, depreciation, amortization, non-cash compensation expense, loss on debt extinguishment and taxes by unconsolidated affiliate, Adjusted EBITDA related to unconsolidated affiliates and distributions received from affiliates for the years ended December 31, 2011 and 2010:

	Years Ended December 31,		
	2011	2010	Change
Equity in earnings of unconsolidated affiliates:			
FEP	$ 24	$ —	$ 24
MEP	—	9	(9)
Other	2	3	(1)
Total equity in earnings of unconsolidated affiliates	$ 26	$ 12	$ 14
Proportionate share of interest, depreciation, amortization, non-cash compensation expense, loss on debt extinguishment and taxes:			
FEP	$ 29	$ —	$ 29
MEP	—	23	(23)
Other	1	—	1
Total proportionate share of interest, depreciation, amortization, non-cash compensation expense, loss on debt extinguishment and taxes	$ 30	$ 23	$ 7
Adjusted EBITDA related to unconsolidated affiliates:			
FEP	$ 53	$ —	$ 53
MEP	—	32	(32)
Other	3	3	—
Total Adjusted EBITDA related to unconsolidated affiliates	$ 56	$ 35	$ 21
Distributions received from unconsolidated affiliates:			
FEP	$ 46	$ —	$ 46
MEP	—	29	(29)
Other	5	4	1
Total distributions received from unconsolidated affiliates	$ 51	$ 33	$ 18

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.

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For additional information regarding our business segments, see "Item 1. Business" and Notes 1 and 14 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 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.

Segment Operating Results

Intrastate Transportation and Storage

	Years Ended December 31,		
	2011	2010	Change
Natural gas transported (MMBtu/d)	11,295,084	12,251,457	(956,373)
Revenues	$2,674	$3,291	$(617)
Cost of products sold	1,774	2,381	(607)
Gross margin	900	910	(10)
Unrealized losses on commodity risk management activities	9	62	(53)
Operating expenses, excluding non-cash compensation expense	(191)	(196)	5
Selling, general and administrative, excluding non-cash compensation expense	(54)	(63)	9
Adjusted EBITDA related to unconsolidated affiliates	3	3	$—
Segment Adjusted EBITDA	$667	$716	(49)

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	$594	$5
Natural gas sales and other	107	110	(3)
Retained fuel revenues	130	144	(14)
Storage margin, including fees	64	62	2
Total gross margin	$900	$910	$(10)

Our gross margin decreased 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 $36 million in 2011 compared to $40 million in 2010. The decrease of $4 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 million primarily due to unfavorable impacts from system optimization activities.

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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 million were recorded in 2011 compared to unrealized losses of $13 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 $14 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.

Storage margin was comprised of the following:

	Years Ended December 31,		
	2011	2010	Change
Withdrawals from storage natural gas inventory (MMBtu)	24,517,008	39,784,446	(15,267,438)
Margin on physical sales	$11	$69	$(58)
Settlements of derivatives	8	1	7
Realized margin on natural gas inventory transactions	19	70	(51)
Fair value adjustments	(52)	(57)	5
Unrealized gains (losses) on derivatives	63	9	54
Margin recognized on natural gas inventory, including related derivatives	30	22	8
Revenues from fee-based storage	35	41	(6)
Other costs	(1)	(1)	—
Total storage margin	$64	$62	$2

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 primarily due to the timing of storage withdrawals and declining forward prices. We also recorded additional mark-to-market losses of $8 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 million due to lower gas prices and a decrease of $7 million in operating and maintenance expense compared to 2010. These decreases were partially offset by higher ad valorem taxes of $2 million due to expansions on our HPL system and increased employee costs of $3 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.

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Interstate Transportation and Storage

	Years Ended December 31,		
	2011	2010	Change
Natural gas transported (MMBtu/d)	2,800,655	1,616,762	1,183,893
Natural gas sold (MMBtu/d)	22,405	23,760	(1,355)
Revenues	$447	$292	$155
Operating expenses, excluding non-cash compensation expense	(93)	(84)	(9)
Selling, general and administrative, excluding non-cash compensation expense	(34)	(20)	(14)
Adjusted EBITDA related to unconsolidated affiliates	53	32	21
Segment Adjusted EBITDA	$373	$220	$153

Volumes. Transported volumes for our interstate transportation and storage segment increased primarily due to an increase in transported volumes of 1,270,656 MMBtu/d on the Tiger pipeline in 2011. The Tiger pipeline was placed in service in December 2010, and the Tiger pipeline expansion was placed in service on August 1, 2011. The incremental transported volumes related to the Tiger pipeline were offset by lower volumes on the Transwestern pipeline.

Revenues. Interstate transportation and storage revenues increased as a result of incremental revenues from the Tiger pipeline and related expansion. Revenues from the Tiger pipeline totaled $188 million in 2011 compared to $10 million in 2010. The incremental revenues from the Tiger pipeline were offset by a decrease in revenues from the Transwestern pipeline of $23 million due to decreases in transportation fees and operations gas sales as a result of lower volumes and prices.

Operating Expenses, Excluding Non-Cash Compensation Expense. Interstate transportation and storage operating expenses increased primarily due to operating expenses incurred on the Tiger pipeline.

Selling, General and Administrative, Excluding Non-Cash Compensation Expense. Interstate transportation and storage selling, general and administrative expenses increased primarily due to increased allocated and employee-related expenses, including incremental amounts related to the Tiger pipeline.

Adjusted EBITDA Related to Unconsolidated Affiliates. Amounts reflected for 2011 primarily represent our proportionate share of such amounts recorded by FEP. Amounts reflected for 2010 primarily represent our proportionate share of such amounts recorded by MEP. We transferred substantially all of our interests in MEP to ETE on May 26, 2010, prior to which we held a 50% interest in MEP. We recorded equity in earnings related to FEP of $24 million in 2011 and equity in earnings related to MEP of $9 million in 2010. In 2011, FEP recorded (on a 100% basis) revenues of $122 million and net income of $48 million.

Midstream

	Years Ended December 31,		
	2011	2010	Change
Gathered Volumes (MMBtu/d)	2,020,126	1,345,860	674,266
NGLs produced (Bbls/d)	54,246	50,602	3,644
Equity NGLs produced (Bbls/d)	16,385	18,870	(2,485)
Revenues	$2,543	$3,128	$(585)
Cost of products sold	2,072	2,750	(678)
Gross margin	471	378	93
Unrealized (gains) losses on commodity risk management activities	(3)	13	(16)
Operating expenses, excluding non-cash compensation expense	(83)	(66)	(17)
Selling, general and administrative, excluding non-cash compensation expense	(19)	(15)	(4)

Adjusted EBITDA attributable to discontinued operations	23	19	4
Segment Adjusted EBITDA	$389	$329	$60

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Volumes. NGL production increased primarily due to increased inlet volumes at our La Grange plant as a result of more favorable processing conditions and more production by our customers in the Eagle Ford Shale area in south Texas. The decrease in equity NGL production was primarily due to a higher concentration of volumes billed under fee-based contracts in 2011 as compared to 2010.

Gross Margin. The components of our midstream segment gross margin were as follows:

	Years Ended December 31,		
	2011	2010	Change
Gathering and processing fee-based revenues	$253	$198	$55
Non fee-based contracts and processing	234	200	34
Other	(16)	(20)	4
Total gross margin	$471	$378	$93

Midstream gross margin increased between the periods due to the net impact of the following:

- Gathering and processing fee-based revenues. Increased volumes from production in the Eagle Ford Shale resulted in increased fee-based revenues of $26 million. Additionally, increased volumes from the growth of our assets in West Virginia and Louisiana provided an increase in our fee-based margin of $18 million.

- Non fee-based contracts and processing margin. Our non fee-based gross margins increased $49 million primarily due to higher NGL prices. The composite NGL price for 2011 was $1.30 per gallon as compared to $1.02 per gallon in 2010. Lower equity NGL production volumes partially offset this increase.

- Other midstream gross margin. The increase in other midstream gross margin was due to increased margin associated with processing where third party processing was utilized. Additionally, we recorded unrealized gains of $3 million in 2011 associated with our marketing activities compared to unrealized losses of $13 million in 2010. For the years ended December 31, 2011 and 2010, other midstream margin was net of $36 million and $40 million, respectively, of fees charged by our intrastate transportation systems. These fees were recognized as income by our intrastate transportation and storage segment and have no effect on our consolidated results of operations.

Unrealized (Gains) Losses on Commodity Risk Management Activities. Our midstream segment recorded unrealized gains of $3 million in 2011 compared to unrealized losses of $13 million in 2010 primarily due to a decrease in the volume of hedging activities of our marketing affiliate.

Operating Expenses, Excluding Non-Cash Compensation Expense. Midstream operating expenses increased $18 million primarily due to an increase in maintenance and operating expenses of $7 million, an increase in ad valorem taxes of $4 million, an increase in employee expenses of $5 million and an increase in professional fees of $2 million. These increases primarily resulted from new assets placed into service in the Eagle Ford Shale.

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation Expense. Midstream selling, general and administrative expenses increased primarily due to increases in professional fees of $4 million and other costs of $2 million offset by a decrease in employee costs of $2 million.

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NGL Transportation and Services

	Years Ended December 31,		
	2011	2010	Change
NGL transportation volumes (Bbls/d)	132,862	—	132,862
NGL fractionation volumes (Bbls/d)	16,475	—	16,475
Revenues	$397	$—	$397
Cost of products sold	218	—	218
Gross margin	179	—	179
Operating expenses, excluding non-cash compensation expense	(39)	—	(39)
Selling, general and administrative, excluding non-cash compensation expense	(13)	—	(13)
Segment Adjusted EBITDA	$127	$—	$127

We own a controlling interest in Lone Star, which acquired all of the membership interests in LDH on May 2, 2011. Results reflected above represent 100% of those of acquired businesses that are engaged in NGL transportation, storage and fractionation from May 2, 2011 to December 31, 2012.
Gross Margin. The components of our NGL transportation and services segment gross margin were as follows:

	Years Ended December 31		
	2011	2010	Change
Storage revenues	$93	$—	$93
Transportation revenues	33	—	33
Processing and fractionation revenues	53	—	53
Total gross margin	$179	$—	$179

All Other

	Years Ended December 31		
	2011	2010	Change
Revenue	$1,656	$1,707	$(51)
Cost of products sold	1,016	1,010	6
Gross margin	640	697	(57)
Unrealized (gains) losses on commodity risk management activities	4	3	1
Operating expenses, excluding non-cash compensation expense	(355)	(349)	(6)
Selling, general and administrative, excluding non-cash compensation expense	(54)	(51)	(3)
Elimination	(10)	(24)	14
Segment Adjusted EBITDA	$225	$276	$(51)

For 2011 and 2010, our “All Other” segment includes our retail propane and other retail propane business, as well as certain other businesses. As discussed below, substantially all of the variances in the “All Other” segment were attributable to the retail propane and other retail propane related business. In January 2012, we contributed the propane business to AmeriGas.

Gross Margin. Total gross margin for our retail propane and other retail propane related business decreased $37.1 million primarily due to a decrease of $4 million in retail fuel margins related to a decline in the average gross margin per gallon sold as well as a decrease of $35 million due to lower volumes as a result of warmer weather and customer conservation. Total propane gross margin also decreased $1 million due to an unfavorable non-cash impact between periods attributable to mark-to-market adjustments on financial instruments used in our commodity price risk management activities. These decreases were slightly offset by a $3 million increase in other retail propane related gross profit.

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Operating Expenses, Excluding Non-Cash Compensation Expense. Operating expenses for our retail propane and other retail propane related business increased $8 million due to increases in net business insurance reserves and claims, $7 million in vehicle fuel and repair expenses and $1 million in general business taxes. These increases were partially offset by decreases of $5 million in performance-based bonus accruals, $2 million in employee wages and benefits and $3 million in other general operating expenses.

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation Expense. Selling, general and administrative expenses for our retail propane and other retail propane related business increased $4 million primarily due to increases in allocated overhead expenses of $2 million and increases in employee wages and benefits of $2 million.

Liquidity and Capital Resources

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

We currently expect the following capital expenditures in 2013 to be within the following ranges:

	Growth		Maintenance[(2)]	
	Low	High	Low	High
Growth capital expenditures:				
ETP Legacy Assets:				
Midstream and intrastate transportation and storage	$ 250	$ 300	$ 80	$ 85
NGL transportation and services [(1)]	400	500	15	20
Interstate transportation and storage	10	20	25	30
	660	820	120	135
Holdco:				
Southern Union transportation and storage	20	30	90	105
Southern Union gathering and processing	170	190	10	15
Sunoco retail marketing	30	60	70	80
	220	280	170	200
Investment in Sunoco Logistics	650	750	60	65
Total projected capital expenditures [(3)]	$ 1,530	$ 1,850	$ 350	$ 400

(1) We expect to receive capital contributions from Regency related to their 30% share of Lone Star of between $100 million and $150 million.

(2) Includes (i) capital expenditures for our intrastate operations for pipeline integrity and for connecting additional wells to our intrastate natural gas systems in order to maintain or increase throughput on existing assets; (ii) capital expenditures for our interstate operations, primarily for pipeline integrity; (iii) capital expenditures related to NGL transportation and services, including amounts expected to be funded by Regency related to its 30% interest in Lone Star; and (iv) capital expenditures related to our crude and retail marketing operations.

(3) Includes capital expenditures related to SUGS through the expected closing date for the pending contribution transaction with Regency.

The assets used in our natural gas operations, including pipelines, gathering systems and related facilities, are generally long-lived assets and do not require significant maintenance capital expenditures. Accordingly, we do not have any significant financial commitments for maintenance capital expenditures in our businesses. From time to time we experience increases in pipe costs due to a number of reasons, including but not limited to, replacing pipe caused by delays from mills, limited selection of mills capable of producing large diameter pipe timely, higher steel prices and other factors beyond our control. However, we include these factors into our anticipated growth capital expenditures for each year.

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In January 2013, we issued senior notes to repay borrowings outstanding under our revolving credit facility and for general partnership purposes.

We generally fund maintenance capital expenditures and distributions with cash flows from operating activities. We generally fund growth capital expenditures with proceeds of borrowings under credit facilities, long-term debt, the issuance of additional Common Units or a combination thereof.

As of December 31, 2012, in addition to $311 million of cash on hand, we had available capacity under our revolving credit facilities of $1.03 billion. Based on our current estimates, we expect to utilize capacity under the ETP Credit Facility, along with cash from operations, to fund our announced growth capital expenditures and working capital needs through the end of 2012; however, we may issue debt or equity securities prior to that time as we deem prudent to provide liquidity for new capital projects, to maintain investment grade credit metrics or other partnership purposes.

Sunoco Logistics' primary sources of liquidity consist of cash generated from operating activities and borrowings under its $585 million of credit facilities. At December 31, 2012, Sunoco Logistics had available borrowing capacity of $446 million under its revolving credit facilities, which includes $15 million of available borrowing capacity from West Texas Gulf's revolving credit facility. In January 2013, the balances outstanding under the Operating Partnership's credit facilities were repaid in connection with a Senior Notes offering. Sunoco Logistics' capital position reflects crude oil and refined products inventories based on historical costs under the last-in, first-out ("LIFO") method of accounting. Sunoco Logistics periodically supplement its cash flows from operations with proceeds from debt and equity financing activities.

In addition to the above capital resources, as of December 31, 2012 Southern Union had available capacity of $490 million under its revolving credit facility.

Cash Flows

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

Operating Activities

Changes in cash flows from operating activities between periods primarily result from changes in earnings (as discussed in "Results of Operations" above), excluding the impacts of non-cash items and changes in operating assets and liabilities. Non-cash items include recurring non-cash expenses, such as depreciation and amortization expense and non-cash compensation expense. The increase in depreciation and amortization expense during the periods presented primarily resulted from construction and acquisitions of assets, while changes in non-cash unit-based compensation expense result from changes in the number of units granted and changes in the grant date fair value estimated for such grants. Cash flows from operating activities also differ from earnings as a result of non-cash charges that may not be recurring such as impairment charges and allowance for equity funds used during construction. The allowance for equity funds used during construction increases in periods when we have a significant amount of interstate pipeline construction in progress. Changes in operating assets and liabilities between periods result from factors such as the changes in the value of price risk management assets and liabilities, timing of accounts receivable collection, payments on accounts payable, the timing of purchase and sales of propane and natural gas inventories, and the timing of advances and deposits received from customers.

Following is a summary of operating activities by period:

Year Ended December 31, 2012

Cash provided by operating activities in 2012 was $1.20 billion and net income was $1.65 billion. The difference between net income and cash provided by operating activities in 2012 primarily consisted of the gain on deconsolidation of our Propane Business of $1.06 billion and net changes in operating assets and liabilities of $475 million offset by non-cash items totaling $1.10 billion. The non-cash activity in 2012 consisted primarily of depreciation and amortization, including amounts attributable to discontinued operations, of $656 million, the write-down of assets included in loss from discontinued operations of $132 million and non-cash compensation expense of $42 million.

Year Ended December 31, 2011

Cash provided by operating activities in 2011 was $1.34 billion and net income was $697 million. The difference between net income and cash provided by operating activities in 2011 consisted of non-cash items totaling $486 million and changes in operating assets and liabilities of $166 million. The non-cash activity in 2011 consisted primarily of depreciation and amortization, including amounts attributable to discontinued operations, of $431 million and non-cash compensation expense of $37 million.

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Year Ended December 31, 2010

Cash provided by operating activities in 2010 was $1.20 billion and net income was $617 million. The difference between net income and cash provided by operating activities in 2010 consisted of non-cash items totaling $417 million, changes in operating assets and liabilities of $125 million, interest rate swap termination proceeds of $26 million and distributions received from our affiliates that exceeded our equity in earnings by $21 million. The non-cash activity in 2010 consisted primarily of depreciation and amortization, including amounts attributable to discontinued operations, of $343 million, non-cash compensation expense of $28 million, and a non-cash impairment of $53 million on our investment in MEP. This impairment was incurred prior to our transfer of substantially all of our investment in MEP to ETE on May 26, 2010. These amounts are partially offset by the allowance for equity funds used during construction of $29 million.

Investing Activities

Cash flows from investing activities primarily consist of cash amounts paid in acquisitions, capital expenditures, and cash contributions to our joint ventures. Changes in capital expenditures between periods primarily result from increases or decreases in our growth capital expenditures to fund our construction and expansion projects.

Following is a summary of investing activities by period:

Year Ended December 31, 2012

Cash used in investing activities in 2012 was $2.29 billion. Total capital expenditures (excluding the allowance for equity funds used during construction) were $2.84 billion. Additional detail related to our capital expenditures is provided in the table below. In addition, in 2012 we paid net cash of $1.25 billion for acquisitions, primarily including amounts related to Citrus and Sunoco. We also received net cash proceeds of $1.44 billion from the contribution of the Propane Business.

Year Ended December 31, 2011

Cash used in investing activities in 2011 was $3.55 billion. Total capital expenditures (excluding the allowance for equity funds used during construction) were $1.42 billion. Additional detail related to our capital expenditures is provided in the table below. In addition, in 2011 we paid cash for acquisitions of $1.97 billion, primarily for the LDH Acquisition, and made net advances to our joint ventures of $200 million.

Year Ended December 31, 2010

Cash used in investing activities in 2010 was $1.49 billion. Total capital expenditures (excluding the allowance for equity funds used during construction) were $1.35 billion. Additional detail related to our capital expenditures is provided in the table below. In addition, in 2010 we paid cash for acquisitions of $178 million.

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Following is a summary of our capital expenditures by period (in millions):

	Capital Expenditures Recorded During Period			(Increase)Decrease in Accrued Capital Expenditures	Capital Expenditures Paid in Cash
	Growth	Maintenance	Total		
Year Ended December 31, 2012:					
ETP Legacy Assets:					
Midstream	$1,096	$28	$1,124	$ (59)	$1,065
Intrastate transportation and storage	18	29	47	2	49
NGL transportation and services	1,291	14	1,305	(75)	1,230
Interstate transportation and storage	12	40	52	7	59
	2,417	111	2,528	(125)	2,403
Holdco:					
Southern Union transportation and storage	6	88	94	(6)	88
Southern Union gathering and processing	178	24	202	(94)	108
Retail Marketing	38	20	58	(19)	39
	222	132	354	(119)	235
Investment in SXL	118	21	139	—	139
Other (including eliminations)	14	49	63	—	63
Total	$2,771	$313	$3,084	$ (244)	$2,840
Year Ended December 31, 2011:					
Intrastate transportation and storage	$16	$41	$57	$ 3	$60
Interstate transportation and storage	181	30	211	32	243
Midstream	826	28	854	(46)	808
NGL transportation and services	317	8	325	(81)	244
Other (including eliminations)	35	27	62	(1)	61
Total	$1,375	$134	$1,509	$ (93)	$1,416
Year Ended December 31, 2010:					
Intrastate transportation and storage	$52	$35	$87	$ 17	$104
Interstate transportation and storage	825	21	846	(32)	814
Midstream	378	16	394	(23)	371
Other (including eliminations)	35	27	62	—	62
Total	$1,290	$99	$1,389	$ (38)	$1,351

Financing Activities

Changes in cash flows from financing activities between periods primarily result from changes in the levels of borrowings and equity issuances, which are primarily used to fund our acquisitions and growth capital expenditures. Distributions to partners increased between the periods based on increases in the number of Common Units outstanding.

Following is a summary of financing activities by period:

Year Ended December 31, 2012

Cash provided by financing activities was $1.29 billion in 2012. We received $791 million in net proceeds from Common Unit offerings. Net proceeds from the offerings were used to repay outstanding borrowings under the ETP Credit Facility, to fund capital expenditures, acquisitions, and capital contributions to joint ventures, as well as for general partnership purposes. In 2012, we had a net increase in our debt level of $1.78 billion primarily due to our issuance of $2.00 billion in aggregate principal amount of senior notes in January 2012 to fund the Citrus Acquisition, partially offset by the repurchase of $750 million in aggregate principal

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amount of senior notes in connection with our tender offers announced in January 2012 (see Note 10 to our consolidated financial statements). In connection with the issuance of senior notes in January 2012, we incurred debt issuance costs of $18 million. In 2012, we paid distributions of $1.34 billion to our partners. In addition, we received capital contributions of $320 million from Regency for its noncontrolling interest in Lone Star.

Year Ended December 31, 2011

Cash provided by financing activities was $2.27 billion in 2011. We received $1.47 billion in net proceeds from Common Unit offerings, including $96 million under our equity distribution program (see Note 7 to our consolidated financial statements). Net proceeds from the offerings were used to repay outstanding borrowings under the ETP Credit Facility, to fund capital expenditures, acquisitions, and capital contributions to joint ventures, as well as for general partnership purposes. In 2011, we had a net increase in our debt level of $1.38 billion primarily due to our issuance of $1.50 billion of senior notes in May 2011 to partially fund the LDH Acquisition. We also received $645 million of capital contributions from noncontrolling interest related to the LDH Acquisition. In 2011, we paid distributions of $1.16 billion to our partners.

Year Ended December 31, 2010

Cash provided by financing activities was $273 million in 2010. We received $1.15 billion in net proceeds from Common Unit offerings, including $239 million under our equity distribution program (see Note 7 to our consolidated financial statements). Net proceeds from the offerings were used to repay borrowings under the ETP Credit Facility, to fund capital expenditures, and capital contributions to joint ventures, as well as for general partnership purposes. In 2010, we had a net increase in our debt level of $193 million primarily due to borrowings to fund capital expenditures and to fund capital contributions to joint ventures, partially offset by the use of proceeds from our Common Unit offerings. In 2010, we paid distributions of $1.07 billion to our partners.

Description of Indebtedness

Our outstanding consolidated indebtedness at December 31, 2012 and 2011 was as follows (in millions):

	December 31,	
	2012	2011
ETP Senior Notes	$7,692	$6,550
Transwestern Senior Unsecured Notes	870	870
Southern Union Senior Notes	1,260	—
Panhandle Senior Notes	1,621	—
Sunoco Senior Notes	965	—
Sunoco Logistics Senior Notes	1,450	—
Revolving credit facilities:		
ETP $2.5 billion Revolving Credit Facility due October 27, 2016	1,395	314
Southern Union $700 million Revolving Credit Facility due May 20, 2016	210	—
Sunoco Logistics $200 million Revolving Credit Facility due August 21, 2013	26	—
Sunoco Logistics $35 million Revolving Credit Facility due April 30, 2015	20	—
Sunoco Logistics $350 million Revolving Credit Facility due August 22, 2016	93	—
Note Payable to ETE	166	—
Other long-term debt	32	81
Unamortized premiums, net of discounts and fair value adjustments	417	(3)
Total debt	16,217	7,812
Less: current maturities	(609)	(424)
Long-term debt, less current maturities	$15,608	$7,388

The terms of our consolidated indebtedness and that of our subsidiaries are described in more detail below and in Note 6 to our consolidated financial statements.

January 2013 Senior Note Offering

In January 2013, ETP completed a public offering of $800 million aggregate principal amount of our 3.6% Senior Notes due February 1, 2023 and $450 million aggregate principal amount of our 5.15% Senior Notes due February 1, 2043. We used the net

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proceeds of approximately $1.24 billion from this offering to repay borrowings outstanding under our revolving credit facility and for general partnership purposes.

In addition, in January 2013, Sunoco Logistics issued $350 million of 3.45% Senior Notes and $350 million of 4.95% Senior Notes (the “2023 and 2043 Senior Notes”), due January 2023 and January 2043, respectively. The terms and conditions of the 2023 and 2043 Senior Notes are comparable to those under Sunoco Logistics' existing Senior Notes. The net proceeds of $691 million from the 2023 and 2043 Senior Notes were used to pay outstanding borrowings under the $350 million and $200 million Credit Facilities and for general partnership purposes.

Revolving Credit Facilities

ETP Credit Facility

The ETP Credit Facility allows for borrowings of up to $2.5 billion and expires in October 2016. The indebtedness under the ETP Credit Facility is unsecured and not guaranteed by any of the Partnership’s subsidiaries and has equal rights to holders of our current and future unsecured debt. The indebtedness under the ETP Credit Facility has the same priority of payment as our other current and future unsecured debt.

We use the ETP Credit Facility to provide temporary financing for our growth projects, as well as for general partnership purposes. We typically repay amounts outstanding under the ETP Credit Facility with proceeds from common unit offerings or long-term notes offerings. The timing of borrowings depends on the Partnership’s activities and the cash available to fund those activities. The repayments of amounts outstanding under the ETP Credit Facility depend on multiple factors, including market conditions and expectations of future working capital needs, and ultimately are a financing decision made by management. Therefore, the balance outstanding under the ETP Credit Facility may vary significantly between periods. We do not believe that such fluctuations indicate a significant change in our liquidity position, because we expect to continue to be able to repay amounts outstanding under the ETP Credit Facility with proceeds from common unit offerings or long-term note offerings.

As of December 31, 2012, we had $1.40 billion outstanding under the ETP Credit Facility, and the amount available for future borrowings was $1.03 billion taking into account letters of credit of $72.0 million. The weighted average interest rate on the total amount outstanding as of December 31, 2012 was 1.71%.

Southern Union Credit Facility

The Southern Union Credit Facility provides for borrowings of up to $700 million and expires in May 2016. Borrowings under the Southern Union Credit Facility are available for working capital, other general company purposes and letter of credit requirements. The interest rate and commitment fee under the Southern Union Credit Facility are calculated using a pricing grid, which is based on the credit ratings for Southern Union's senior unsecured notes. The weighted average interest rate on the total amount outstanding as of December 31, 2012 was 1.84%.

On August 10, 2012, Southern Union entered into a First Amendment of the Southern Union Credit Facility. The amendment provides for, among other things, (i) a revision to the change of control definition to permit equity ownership of Southern Union by ETP or any direct subsidiaries of ETP in addition to ETE or any direct or indirect subsidiary of ETE; and (ii) a waiver of any potential default that may result from the Holdco Transaction.

Sunoco Logistics Credit Facilities

Sunoco Logistics maintains two credit facilities to fund its working capital requirements, finance acquisitions and capital projects and for general partnership purposes. The credit facilities consist of a $350 million unsecured credit facility which expires in August 2016 (the “$350 million Credit Facility”) and a $200 million unsecured credit facility which expires in August 2013 (the “$200 million Credit Facility”). Outstanding borrowings under $350 million Credit Facility and $200 million Credit Facility were $93 million and $26 million, respectively, at December 31, 2012.

In May 2012, West Texas Gulf entered into a $35 million revolving credit facility (the “$35 million Credit Facility”) which expires in April 2015. The facility is available to fund West Texas Gulf’s general corporate purposes including working capital and capital expenditures. Outstanding borrowings under this credit facility were $20 million at December 31, 2012.

Covenants Related to ETP Credit Agreements

The agreements relating to the ETP Senior Notes contain restrictive covenants customary for an issuer with an investment-grade rating from the rating agencies, which covenants include limitations on liens and a restriction on sale-leaseback transactions.

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The credit agreement relating to the ETP Credit Facility contains covenants that limit (subject to certain exceptions) the Partnership's and certain of the Partnership's subsidiaries' ability to, among other things:

- incur indebtedness;
- grant liens;
- enter into mergers;
- dispose of assets;
- make certain investments;
- make Distributions (as defined in such credit agreement) during certain Defaults (as defined in such credit agreement) and during any Event of Default (as defined in such credit agreement);
- engage in business substantially different in nature than the business currently conducted by the Partnership and its subsidiaries;
- engage in transactions with affiliates; and
- enter into restrictive agreements;

The credit agreement relating to the ETP Credit Facility also contains a financial covenant that provides that the Leverage Ratio, as defined in the ETP Credit Facility, shall not exceed 5.0 to 1 as of the end of each quarter, with a permitted increase to 5.5 to 1 during a Specified Acquisition Period, as defined in the ETP Credit Facility.

The agreements relating to the Transwestern senior notes contain certain restrictions that, among other things, limit the incurrence of additional debt, the sale of all or substantially all assets and the payment of dividends and specify a maximum debt to capitalization ratio.

We are required to assess compliance quarterly and were in compliance with all requirements, limitations, and covenants related to debt agreements as of December 31, 2012.

Each of the agreements referred to above are incorporated herein by reference to our reports previously filed with the SEC under the Exchange Act. See "Item 1. Business – SEC Reporting."

Covenants Related to Southern Union's Credit Agreements

Southern Union is not party to any lending agreement that would accelerate the maturity date of any obligation due to a failure to maintain any specific credit rating, nor would a reduction in any credit rating, by itself, cause an event of default under any of Southern Union's lending agreements. Financial covenants exist in certain of Southern Union's debt agreements. A failure by Southern Union to satisfy any such covenant would give rise to an event of default under the associated debt, which could become immediately due and payable if Southern Union did not cure such default within any permitted cure period or if Southern Union did not obtain amendments, consents or waivers from its lenders with respect to such covenants.

Southern Union's restrictive covenants include restrictions on debt levels, restrictions on liens securing debt and guarantees, restrictions on mergers and on the sales of assets, capitalization requirements, dividend restrictions, cross default and cross-acceleration and prepayment of debt provisions. A breach of any of these covenants could result in acceleration of Southern Union's debt and other financial obligations and that of its subsidiaries. Under the current credit agreements, the financial covenants are as follows:

- Under the Southern Union Credit Facility, the ratio of consolidated funded debt to consolidated earnings before interest, taxes, depreciation and amortization, as defined therein, cannot exceed 5.25 times through December 31, 2012 and 5.00 times thereafter;
- Under the Southern Union Credit Facility, in the event Southern Union's credit rating falls below investment grade, the ratio of consolidated earnings before interest, taxes, depreciation and amortization to consolidated interest expense, as defined therein, cannot be less than 2.00 times; and
- Under LNG Holding's $455 million term loan, the ratio of consolidated funded debt to consolidated earnings before interest, taxes, depreciation and amortization, as defined therein, for Panhandle cannot exceed 5.00 times.

In addition to the above financial covenants, Southern Union and/or its subsidiaries are subject to certain additional restrictions and covenants. These restrictions and covenants include limitations on additional debt at some of its subsidiaries; limitations on the use of proceeds from borrowing at some of its subsidiaries; limitations, in some cases, on transactions with its affiliates; limitations on the incurrence of liens; potential limitations on the abilities of some of its subsidiaries to declare and pay dividends

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and potential limitations on some of its subsidiaries to participate in Southern Union’s cash management program; and limitations on Southern Union’s ability to prepay debt.

Covenants Related to Sunoco Logistics Credit Agreements

The $350 and $200 million Credit Facilities contain various covenants limiting Sunoco Logistics' ability to incur indebtedness; grant certain liens; make certain loans, acquisitions and investments; make any material change to the nature of its business; or enter into a merger or sale of assets, including the sale or transfer of interests in the Operating Partnership’s subsidiaries. The credit facilities also limit Sunoco Logistics, on a rolling four-quarter basis, to a maximum total consolidated debt to consolidated EBITDA ratio, as defined in the underlying credit agreements, of 5.0 to 1, which can generally be increased to 5.5 to 1 during an acquisition period. Sunoco Logistics' ratio of total debt to Adjusted EBITDA was 2.0 to 1 at December 31, 2012, as calculated in accordance with the credit agreements.

The credit facility also limits West Texas Gulf, on a rolling four-quarter basis, to a minimum fixed charge coverage ratio, as defined in the underlying credit agreement. The ratio for the fiscal quarter ending December 31, 2012 shall not be less than 1.00 to 1. The minimum ratio fluctuates between 0.80 to 1 and 1.00 to 1 throughout the term of the revolver as specified in the credit agreement. In addition, the credit facility limits West Texas Gulf to a maximum leverage ratio of 2.00 to 1. West Texas Gulf’s fixed charge coverage ratio and leverage ratio were 1.29 to 1 and 0.62 to 1, respectively, at December 31, 2012.

Contingent Residual Support Agreement - AmeriGas

In order to finance the cash portion of the purchase price of the Propane Business described in Note 6 of our consolidated financial statements, AmeriGas Finance LLC ("Finance Company"), a wholly owned subsidiary of AmeriGas, issued $550 million in aggregate principal amount of 6.75% Senior Notes due 2020 and $1.0 billion in aggregate principal amount of 7.00% Senior Notes due 2022. AmeriGas borrowed $1.5 billion of the proceeds of the Senior Notes issuance from Finance Company through an intercompany borrowing having maturity dates and repayment terms that mirror those of the Senior Notes (the "Supported Debt").

In connection with the closing of the contribution of the Propane Business, ETP entered into a Contingent Residual Support Agreement ("CRSA") with AmeriGas, Finance Company, AmeriGas Finance Corp. and UGI Corp., pursuant to which ETP will provide contingent, residual support of the Supported Debt, as defined in the CRSA.

Contractual Obligations

The following table summarizes our long-term debt and other contractual obligations as of December 31, 2012, excluding amounts related to our discontinued operations (see Note 3 to our consolidated financial statements)(in millions):

	Payments Due by Period				
Contractual Obligations	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Long-term debt	$15,800	$609	$2,448	$3,182	$9,561
Interest on long-term debt (a)	11,135	892	1,583	1,356	7,304
Payments on derivatives	155	84	71	—	—
Purchase commitments (b)	63,711	12,464	14,711	13,705	22,831
Transportation, natural gas storage and fractionation contracts	431	56	130	119	126
Operating lease obligations	822	90	158	114	460
Other	271	75	86	39	71
Totals (c)	$92,325	$14,270	$19,187	$18,515	$40,353

(a) Interest payments on long-term debt are based on the principal amount of debt obligations as of December 31, 2012. With respect to variable rate debt, the interest payments were estimated using the interest rate as of December 31, 2012. To the extent interest rates change, our contractual obligations for interest payments will change. See “Item 7A. Quantitative and Qualitative Disclosures About Market Risk” for further discussion.

(b) We define a purchase commitment as an agreement to purchase goods or services that is enforceable and legally binding (unconditional) on us that specifies all significant terms, including: fixed or minimum quantities to be purchased; fixed, minimum or variable price provisions; and the approximate timing of the transactions. We have long and short-term product purchase obligations for refined product and energy commodities with third-party suppliers. These purchase obligations are entered into at either variable or fixed prices. The purchase prices that we are obligated to pay under variable price contracts

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approximate market prices at the time we take delivery of the volumes. Our estimated future variable price contract payment obligations are based on the December 31, 2012 market price of the applicable commodity applied to future volume commitments. Actual future payment obligations may vary depending on market prices at the time of delivery. The purchase prices that we are obligated to pay under fixed price contracts are established at the inception of the contract. Our estimated future fixed price contract payment obligations are based on the contracted fixed price under each commodity contract. Obligations shown in the table represent estimated payment obligations under these contracts for the periods indicated. Approximately $61 billion of total purchase commitments relate to production from PES.

(c) Excludes non-current deferred tax liabilities of $3.48 billion due to uncertainty of the timing of future cash flows for such liabilities.

Cash Distributions

We expect to use substantially all of our cash provided by operating and financing activities from the Operating Companies to provide distributions to our Unitholders. Under our Partnership Agreement, we will distribute to our partners within 45 days after the end of each calendar quarter, an amount equal to all of our Available Cash (as defined in our Partnership Agreement) for such quarter. Available Cash generally means, with respect to any quarter of the Partnership, all cash on hand at the end of such quarter less the amount of cash reserves established by the General Partner in its reasonable discretion that is necessary or appropriate to provide for future cash requirements. Our commitment to our Unitholders is to distribute the increase in our cash flow while maintaining prudent reserves for our operations.

Distributions declared are summarized as follows:

	Record Date	Payment Date	Amount per Unit
Year Ended December 31, 2012	November 6, 2012	November 14, 2012	$0.89375
	August 6, 2012	August 14, 2012	0.89375
	May 4, 2012	May 15, 2012	0.89375
	February 7, 2012	February 14, 2012	0.89375
Year Ended December 31, 2011	November 4, 2011	November 14, 2011	$0.89375
	August 5, 2011	August 15, 2011	0.89375
	May 6, 2011	May 16, 2011	0.89375
	February 7, 2011	February 14, 2011	0.89375
Year Ended December 31, 2010	November 8, 2010	November 15, 2010	$0.89375
	August 9, 2010	August 16, 2010	0.89375
	May 7, 2010	May 17, 2010	0.89375
	February 8, 2010	February 15, 2010	0.89375

On January 28, 2013, we declared a cash distribution for the three months ended December 31, 2012 of $0.89375 per Common Unit, or $3.575 annualized. We paid this distribution on February 14, 2013 to Unitholders of record at the close of business on February 7, 2013.

The total amounts of distributions declared during the periods presented (all from Available Cash from our operating surplus and are shown in the year with respect to which they relate) are as follows (in millions):

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	Years Ended December 31,		
	2012	2011	2010
Distributions to be paid to the partners of ETP:			
Limited Partners:			
Common units held by ETE	$180	$180	$180
Common units held by public	783	582	497
General Partner interest held by ETE	20	20	20
IDRs held by ETE	529	422	376
	1,512	1,204	1,073
IDR relinquishment related to Citrus Dropdown and Sunoco Merger	(90)	—	—
Total distributions to be paid to the partners of ETP	$1,422	$1,204	$1,073
Distributions to be paid to noncontrolling interests:			
Distributions to ETE in respect of Holdco	$75	$—	$—
Distributions to Regency in respect of Lone Star	60	35	—
Distributions to Sunoco Logistics unitholders (common units held by public)	38	—	—
Total distributions to be paid to noncontrolling interests	173	35	—
Total distributions to be paid to the partners of ETP and noncontrolling interests	$1,595	$1,239	$1,073

New Accounting Standards

None.

Estimates and Critical Accounting Policies

The selection and application of accounting policies is an important process that has developed as our business activities have evolved and as the accounting rules have developed. Accounting rules generally do not involve a selection among alternatives, but involve an implementation and interpretation of existing rules, and the use of judgment applied to the specific set of circumstances existing in our business. We make every effort to properly comply with all applicable rules, and we believe the proper implementation and consistent application of the accounting rules are critical. Our critical accounting policies are discussed below. For further details on our accounting policies see Note 2 to our consolidated financial statements.

Use of Estimates. The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the accrual for and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The natural gas industry conducts its business by processing actual transactions at the end of the month following the month of delivery. Consequently, the most current month’s financial results for the midstream, NGL and intrastate transportation and storage segments are estimated using volume estimates and market prices. Any differences between estimated results and actual results are recognized in the following month’s financial statements. Management believes that the operating results estimated for the year ended December 31, 2012 represent the actual results in all material respects.

Some of the other significant estimates made by management include, but are not limited to, the timing of certain forecasted transactions that are hedged, the fair value of derivative instruments, useful lives for depreciation and amortization, purchase accounting allocations and subsequent realizability of intangible assets, fair value measurements used in the goodwill impairment test, market value of inventory, assets and liabilities resulting from the regulated ratemaking process, contingency reserves and environmental reserves. Actual results could differ from those estimates.

Revenue Recognition. Revenues for sales of natural gas and NGLs are recognized at the later of the time of delivery of the product to the customer or the time of sale. Revenues from service labor, transportation, treating, compression and gas processing, are recognized upon completion of the service. Transportation capacity payments are recognized when earned in the period the capacity is made available.

Our intrastate transportation and storage and interstate transportation and storage segments’ 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. Excess fuel retained after consumption is typically valued at market prices.

Our intrastate transportation and storage segment also generates revenues and margin from the sale of natural gas to electric utilities, independent power plants, local distribution companies, industrial end-users and other marketing companies on the HPL System. Generally, we purchase natural gas from the market, including purchases from the midstream segment's marketing operations, and from producers at the wellhead.

In addition, our intrastate transportation and storage segment generates revenues and margin from fees charged for storing customers' working natural gas in our storage facilities. We also engage in natural gas storage transactions in which we seek to find and profit from pricing differences that occur over time utilizing the Bammel storage reservoir. We purchase physical natural gas and then sell financial contracts at a price sufficient to cover our carrying costs and provide for a gross profit margin. We expect margins from natural gas storage transactions to be higher during the periods from November to March of each year and lower during the period from April through October of each year due to the increased demand for natural gas during colder weather. However, we cannot assure that management's expectations will be fully realized in the future and in what time period, due to various factors including weather, availability of natural gas in regions in which we operate, competitive factors in the energy industry, and other issues.

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

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

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

We have a risk management policy that provides for oversight over our marketing activities. These activities are monitored independently by our risk management function and must take place within predefined limits and authorizations. As a result of our use of derivative financial instruments that may not qualify for hedge accounting, the degree of earnings volatility that can occur may be significant, favorably or unfavorably, from period to period. We attempt to manage this volatility through the use of daily position and profit and loss reports provided to senior management and predefined limits and authorizations set forth in our risk management policy.

We inject and hold natural gas in our Bammel storage facility to take advantage of contango markets, 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. At the inception of the hedge, we lock in a margin by purchasing gas in the spot market or off peak season and entering a financial contract to lock in the sale price. If we designate the related financial contract as a fair value hedge for accounting purposes, we value the hedged natural gas inventory at current spot market prices along with the financial derivative we use to hedge it. Changes in the spread between the forward natural gas prices designated as fair value hedges and the physical inventory spot prices result in unrealized gains or losses until the underlying physical gas is withdrawn and the related designated 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. Unrealized margins represent the unrealized gains or losses from our derivative instruments using mark-to-market accounting, with changes in the fair value of our derivatives being recorded directly in earnings. These margins fluctuate based upon changes in the spreads between the physical spot prices and forward natural gas prices. If the spread narrows between the physical and financial prices, we will record unrealized gains or lower unrealized losses. If the spread widens, we will record unrealized losses or lower unrealized gains. Typically, as we enter the winter months, the spread converges so that we recognize in earnings the original locked in spread, either through mark-to-market or the physical withdrawal of natural gas.

NGL storage and pipeline transportation revenues are recognized when services are performed or products are delivered, respectively. Fractionation and processing revenues are recognized when product is either loaded into a truck or injected into a third party pipeline, which is when title and risk of loss pass to the customer.

In our natural gas compression business, revenue is recognized for compressor packages and technical service jobs using the completed contract method which recognizes revenue upon completion of the job. Costs incurred on a job are deducted at the time revenue is recognized.

Regulatory Assets and Liabilities. Our interstate transportation and storage segment is subject to regulation by certain state and federal authorities and has accounting policies that conform to the accounting requirements and ratemaking practices of the regulatory authorities. The application of these accounting policies allows us to defer expenses and revenues on the balance sheet as regulatory assets and liabilities when it is probable that those expenses and revenues will be allowed in the ratemaking process in a period different from the period in which they would have been reflected in the consolidated statement of operations by an unregulated company. These deferred assets and liabilities will be reported in results of operations in the period in which the same amounts are included in rates and recovered from or refunded to customers. Management's assessment of the probability of recovery or pass through of regulatory assets and liabilities will require judgment and interpretation of laws and regulatory commission orders. If, for any reason, we cease to meet the criteria for application of regulatory accounting treatment for all or part of our operations, the regulatory assets and liabilities related to those portions ceasing to meet such criteria would be eliminated from the consolidated balance sheet for the period in which the discontinuance of regulatory accounting treatment occurs.

Accounting for Derivative Instruments and Hedging Activities. We utilize various exchange-traded and over-the-counter commodity financial instrument contracts to limit our exposure to margin fluctuations in natural gas, NGL and refined products. These contracts consist primarily of futures and swaps. In addition, prior to the contribution of our retail propane activities to AmeriGas, we used derivatives to limit our exposure to propane market prices.

If we designate a derivative financial instrument as a cash flow hedge and it qualifies for hedge accounting, the change in the fair value is deferred in accumulated other comprehensive income ("AOCI") until the underlying hedged transaction occurs. Any ineffective portion of a cash flow hedge's change in fair value is recognized each period in earnings. Gains and losses deferred in AOCI related to cash flow hedges remain in AOCI until the underlying physical transaction occurs, unless it is probable that the forecasted transaction will not occur by the end of the originally specified time period or within an additional two-month period of time thereafter. For financial derivative instruments that do not qualify for hedge accounting, the change in fair value is recorded in cost of products sold in the consolidated statements of operations.

If we designate a hedging relationship as a fair value hedge, we record the changes in fair value of the hedged asset or liability in cost of products sold in our consolidated statement of operations. This amount is offset by the changes in fair value of the related hedging instrument. Any ineffective portion or amount excluded from the assessment of hedge ineffectiveness is also included in the cost of products sold in the consolidated statement of operations.

We utilize published settlement prices for exchange-traded contracts, quotes provided by brokers, and estimates of market prices based on daily contract activity to estimate the fair value of these contracts. Changes in the methods used to determine the fair value of these contracts could have a material effect on our results of operations. We do not anticipate future changes in the methods used to determine the fair value of these derivative contracts. See "Item 7A. Quantitative and Qualitative Disclosures about Market Risk" for further discussion regarding our derivative activities.

Fair Value of Financial Instruments. We have marketable securities, commodity derivatives and interest rate derivatives that are accounted for as assets and liabilities at fair value in our consolidated balance sheets. We determine the fair value of our assets and liabilities subject to fair value measurement by using the highest possible "level" of inputs. Level 1 inputs are observable quotes in an active market for identical assets and liabilities. We consider the valuation of marketable securities and commodity derivatives transacted through a clearing broker with a published price from the appropriate exchange as a Level 1 valuation. Level 2 inputs are inputs observable for similar assets and liabilities. We consider over-the-counter ("OTC") commodity derivatives entered into directly with third parties as a Level 2 valuation since the values of these derivatives are quoted on an exchange for similar transactions. Additionally, we consider our options transacted through our clearing broker as having Level 2 inputs due to the level of activity of these contracts on the exchange in which they trade. We consider the valuation of our interest rate derivatives as Level 2 as the primary input, the LIBOR curve, is based on quotes from an active exchange of Eurodollar futures for the same period as the future interest swap settlements. Level 3 inputs are unobservable. We currently do not have any recurring fair value measurements that are considered Level 3 valuations.

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Impairment of Long-Lived Assets and Goodwill. Long-lived assets are required to be tested for recoverability whenever events or changes in circumstances indicate that the carrying amount of the asset may not be recoverable. Goodwill and intangibles with indefinite lives must be tested for impairment annually or more frequently if events or changes in circumstances indicate that the related asset might be impaired. An impairment loss should be recognized only if the carrying amount of the asset/goodwill is not recoverable and exceeds its fair value.

In order to test for recoverability when performing a quantitative impairment test, we must make estimates of projected cash flows related to the asset, which include, but are not limited to, assumptions about the use or disposition of the asset, estimated remaining life of the asset, and future expenditures necessary to maintain the asset's existing service potential. In order to determine fair value, we make certain estimates and assumptions, including, among other things, changes in general economic conditions in regions in which our markets are located, the availability and prices of natural gas and propane supply, our ability to negotiate favorable sales agreements, the risks that natural gas exploration and production activities will not occur or be successful, our dependence on certain significant customers and producers of natural gas, and competition from other midstream companies, including major energy producers. While we believe we have made reasonable assumptions to calculate the fair value, if future results are not consistent with our estimates, we could be exposed to future impairment losses that could be material to our results of operations.

Property, Plant and Equipment. Expenditures for maintenance and repairs that do not add capacity or extend the useful life are expensed as incurred. Expenditures to refurbish assets that either extend the useful lives of the asset or prevent environmental contamination are capitalized and depreciated over the remaining useful life of the asset. Additionally, we capitalize certain costs directly related to the construction of assets including internal labor costs, interest and engineering costs. Upon disposition or retirement of pipeline components or natural gas plant components, any gain or loss is recorded to accumulated depreciation. When entire pipeline systems, gas plants or other property and equipment are retired or sold, any gain or loss is included in the consolidated statement of operations. Depreciation of property, plant and equipment is provided using the straight-line method based on their estimated useful lives ranging from 3 to 83 years. Changes in the estimated useful lives of the assets could have a material effect on our results of operation. We do not anticipate future changes in the estimated useful lives of our property, plant and equipment.

Asset Retirement Obligation. We have determined that we are obligated by contractual or regulatory requirements to remove facilities or perform other remediation upon retirement of certain assets. The fair value of any ARO is determined based on estimates and assumptions related to retirement costs, which the Partnership bases on historical retirement costs, future inflation rates and credit-adjusted risk-free interest rates. These fair value assessments are considered to be level 3 measurements, as they are based on both observable and unobservable inputs. Changes in the liability are recorded for the passage of time (accretion) or for revisions to cash flows originally estimated to settle the ARO.

An ARO is required to be recorded when a legal obligation to retire an asset exists and such obligation can be reasonably estimated. We will record an asset retirement obligation in the periods in which management can reasonably determine the settlement dates.

Except for the AROs of Southern Union, Sunoco Logistics and Sunoco discussed below, management was not able to reasonably measure the fair value of asset retirement obligations as of December 31, 2012 and 2011 because the settlement dates were indeterminable. Although a number of other onshore assets in Southern Union's system are subject to agreements or regulations that give rise to an ARO upon Southern Union's discontinued use of these assets, AROs were not recorded because these assets have an indeterminate removal or abandonment date given the expected continued use of the assets with proper maintenance or replacement. Sunoco has legal asset retirement obligations for several other assets at its refineries, pipelines and terminals, for which it is not possible to estimate when the obligations will be settled. Consequently, the retirement obligations for these assets cannot be measured at this time. At the end of the useful life of these underlying assets, Sunoco is legally or contractually required to abandon in place or remove the asset. Sunoco Logistics believes it may have additional asset retirement obligations related to its pipeline assets and storage tanks, for which it is not possible to estimate whether or when the retirement obligations will be settled. Consequently, these retirement obligations cannot be measured at this time.

Individual component assets have been and will continue to be replaced, but the pipeline and the natural gas gathering and processing systems will continue in operation as long as supply and demand for natural gas exists. Based on the widespread use of natural gas in industrial and power generation activities, management expects supply and demand to exist for the foreseeable future. We have in place a rigorous repair and maintenance program that keeps the pipelines and the natural gas gathering and processing systems in good working order. Therefore, although some of the individual assets may be replaced, the pipelines and the natural gas gathering and processing systems themselves will remain intact indefinitely.

As of December 31, 2012, there were no legally restricted funds for the purpose of settling AROs.

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Pensions and Other Postretirement Benefit Plans

The Partnership is required to measure plan assets and benefit obligations as of its fiscal year-end balance sheet date. The Partnership recognizes the changes in the funded status of its defined benefit postretirement plans through AOCI. The calculation of the net periodic benefit cost and benefit obligation requires the use of a number of assumptions. Changes in these assumptions can have a significant effect on the amounts reported in the financial statements. The Partnership believes that the two most critical assumptions are the assumed discount rate and the expected rate of return on plan assets.

The discount rate is established by using the Citigroup Pension Discount Curve as published on the Society of Actuaries website as the hypothetical portfolio of high-quality debt instruments that would provide the necessary cash flows to pay the benefits when due. Net periodic benefit cost and benefit obligation increases and equity correspondingly decreases as the discount rate is reduced.

The expected rate of return on plan assets is based on long-term expectations given current investment objectives and historical results. Net periodic benefit cost increases as the expected rate of return on plan assets is correspondingly reduced.

Legal Matters. We are subject to litigation and regulatory proceedings as a result of our business operations and transactions. We utilize both internal and external counsel in evaluating our potential exposure to adverse outcomes from claims, orders, judgments or settlements. To the extent that actual outcomes differ from our estimates, or additional facts and circumstances cause us to revise our estimates, our earnings will be affected. We expense legal costs as incurred, and all recorded legal liabilities are revised, as required, as better information becomes available to us. The factors we consider when recording an accrual for contingencies include, among others: (i) the opinions and views of our legal counsel; (ii) our previous experience; and (iii) the decision of our management as to how we intend to respond to the complaints.

For more information on our litigation and contingencies, see Note 8 to our consolidated financial statements included in "Item 8. Financial Statements and Supplementary Data" in this report.

Environmental Remediation Activities. Sunoco's accrual for environmental remediation activities reflects anticipated work at identified sites where an assessment has indicated that cleanup costs are probable and reasonably estimable. The accrual is undiscounted and is based on currently available information, estimated timing of remedial actions and related inflation assumptions, existing technology and presently enacted laws and regulations. It is often extremely difficult to develop reasonable estimates of future site remediation costs due to changing regulations, changing technologies and their associated costs, and changes in the economic environment. Engineering studies, historical experience and other factors are used to identify and evaluate remediation alternatives and their related costs in determining the estimated accruals for environmental remediation activities. Losses attributable to unasserted claims are also reflected in the accruals to the extent they are probable of occurrence and reasonably estimable.

In general, each remediation site/issue is evaluated individually based upon information available for the site/issue and no pooling or statistical analysis is used to evaluate an aggregate risk for a group of similar items (e.g., service station sites) in determining the amount of probable loss accrual to be recorded. Sunoco's estimates of environmental remediation costs also frequently involve evaluation of a range of estimates. In many cases, it is difficult to determine that one point in the range of loss estimates is more likely than any other. In these situations, existing accounting guidance requires that the minimum of the range be accrued. Accordingly, the low end of the range often represents the amount of loss which has been recorded.

In addition to the probable and estimable losses which have been recorded, management believes it is reasonably possible (i.e., less than probable but greater than remote) that additional environmental remediation losses will be incurred. At December 31, 2012, the aggregate of the estimated maximum additional reasonably possible losses, which relate to numerous individual sites, totaled approximately $200 million. This estimate of reasonably possible losses associated with environmental remediation is largely based upon analysis during 2012 and continuing into early 2013 of the potential liabilities associated with the establishment of the segregated environmental fund discussed above. It also includes estimates for remediation activities at current logistics and retail assets. This reasonably possible loss estimate in many cases reflects the upper end of the loss ranges which are described above. Such estimates include potentially higher contractor costs for expected remediation activities, the potential need to use more

costly or comprehensive remediation methods and longer operating and monitoring periods, among other things.
Total future costs for environmental remediation activities will depend upon, among other things, the identification of any additional sites, the determination of the extent of the contamination at each site, the timing and nature of required remedial actions, the nature of operations at each site, the technology available and needed to meet the various existing legal requirements, the nature and terms of cost-sharing arrangements with other potentially responsible parties, the availability of insurance coverage, the nature and extent of future environmental laws and regulations, inflation rates, terms of consent agreements or remediation permits with regulatory agencies and the determination of Sunoco's liability at the sites, if any, in light of the number, participation level and financial viability of the other parties. The recognition of additional losses, if and when they were to occur, would likely extend

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over many years. Management believes that none of the current remediation locations, which are in various stages of ongoing remediation, is individually material to Sunoco as its largest accrual for any one Superfund site, operable unit or remediation area was approximately $28 million at December 31, 2012. As a result, Sunoco’s exposure to adverse developments with respect to any individual site is not expected to be material. However, if changes in environmental laws or regulations occur or the assumptions used to estimate losses at multiple sites are adjusted, such changes could impact multiple Sunoco facilities, formerly owned facilities and third-party sites at the same time. As a result, from time to time, significant charges against income for environmental remediation may occur; however, management does not believe that any such charges would have a material adverse impact on the Company’s consolidated financial position.

Deferred Income Taxes. ETP recognizes benefits in earnings and related deferred tax assets for net operating loss carryforwards (“NOLs”) and tax credit carryforwards. If necessary, a charge to earnings and a related valuation allowance are recorded to reduce deferred tax assets to an amount that is more likely than not to be realized by the Partnership in the future. Deferred income tax assets attributable to state and federal NOLs and federal tax alternative minimum tax credit carryforwards totaling $268 million have been included in ETP's consolidated balance sheet as of December 31, 2012. All of the deferred income tax assets attributable to state and federal NOL benefits expiring before 2032 as more fully described below and the federal alternative minimum tax credits are attributable to the acquisitions of Southern Union and Sunoco. The state NOL carryforward benefits of 104 million begin to expire in 2013 with a substantial portion expiring between 2029 and 2032. The federal NOLs benefits of $127 million expire between 2030 and 2032, while the $37 million of the federal tax alternative minimum tax credit carryforwards have no expiration date. We have determined that a valuation allowance totaling $90 million (net of federal income tax effects) is required for the state NOLs at December 31, 2012 primarily due to significant restrictions on their use in the Commonwealth of Pennsylvania. In making the assessment of the future realization of the deferred tax assets, we rely on future reversals of existing taxable temporary differences, tax planning strategies and forecasted taxable income based on historical and projected future operating results. The potential need for valuation allowances is regularly reviewed by management. If it is more likely than not that the recorded asset will not be realized, additional valuation allowances which increase income tax expense may be recognized in the period such determination is made. Likewise, if it is more likely than not that additional deferred tax assets will be realized, an adjustment to the deferred tax asset will increase income in the period such determination is made.

Forward-Looking Statements

This annual report contains various forward-looking statements and information that are based on our beliefs and those of our General Partner, as well as assumptions made by and information currently available to us. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. When used in this annual report, words such as “anticipate,” “project,” “expect,” “plan,” “goal,” “forecast,” “estimate,” “intend “believe,” “may,” “will” and similar expressions and statements regarding our plans and objectives for future operations, are intended to identify forward-looking statements. Although we and our General Partner believe that the expectations on which such forward-looking statements are based are reasonable, neither we nor our General Partner can give assurances that such expectations will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected.

Among the key risk factors that may have a direct bearing on our results of operations and financial condition are:

- the volumes transported on our pipelines and gathering systems;
- the level of throughput in our processing and treating facilities;
- the fees we charge and the margins we realize for our gathering, treating, processing, storage and transportation services;
- the prices and market demand for, and the relationship between, natural gas and NGLs;
- energy prices generally;
- the prices of natural gas and NGLs compared to the price of alternative and competing fuels;
- the general level of petroleum product demand and the availability and price of NGL supplies;
- the level of domestic oil, natural gas and NGL production;

- the availability of imported oil, natural gas and NGLs;
- actions taken by foreign oil and gas producing nations;
- the political and economic stability of petroleum producing nations;
- the effect of weather conditions on demand for oil, natural gas and NGLs;
- availability of local, intrastate and interstate transportation systems;

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- the continued ability to find and contract for new sources of natural gas supply;
- availability and marketing of competitive fuels;
- the impact of energy conservation efforts;
- energy efficiencies and technological trends;
- governmental regulation and taxation;
- changes to, and the application of, regulation of tariff rates and operational requirements related to our interstate and intrastate pipelines;
- hazards or operating risks incidental to the gathering, treating, processing and transporting of natural gas and NGLs;
- competition from other midstream companies and interstate pipeline companies;
- loss of key personnel;
- loss of key natural gas producers or the providers of fractionation services;
- reductions in the capacity or allocations of third-party pipelines that connect with our pipelines and facilities;
- the effectiveness of risk-management policies and procedures and the ability of our liquids marketing counterparties to satisfy their financial commitments;
- the nonpayment or nonperformance by our customers;
- regulatory, environmental, political and legal uncertainties that may affect the timing and cost of our internal growth projects, such as our construction of additional pipeline systems;
- risks associated with the construction of new pipelines and treating and processing facilities or additions to our existing pipelines and facilities, including difficulties in obtaining permits and rights-of-way or other regulatory approvals and the performance by third-party contractors;
- the availability and cost of capital and our ability to access certain capital sources;
- a deterioration of the credit and capital markets;
- risks associated with the assets and operations of entities in which we own less than a controlling interests, including risks related to management actions at such entities that we may not be able to control or exert influence;
- the ability to successfully identify and consummate strategic acquisitions at purchase prices that are accretive to our financial results and to successfully integrate acquired businesses;
- changes in laws and regulations to which we are subject, including tax, environmental, transportation and employment regulations or new interpretations by regulatory agencies concerning such laws and regulations; and
- the costs and effects of legal and administrative proceedings.

You should not put undue reliance on any forward-looking statements. When considering forward-looking statements, please review the risks described under “Item 1A. Risk Factors” in this annual report. Any forward-looking statement made by us in this Annual Report on Form 10-K is based only on information currently available to us and speaks only as of the date on which it is made. We undertake no obligation to publicly update any forward-looking statement, whether written or oral, that may be made from time to time, whether as a result of new information, future developments or otherwise.

Inflation

Interest rates on existing and future credit facilities and future debt offerings could be significantly higher than current levels, causing our financing costs to increase accordingly. Although increased financing costs could limit our ability to raise funds in the capital markets, we expect to remain competitive with respect to acquisitions and capital projects since our competitors would face similar circumstances.

Inflation in the United States has been relatively low in recent years and has not had a material effect on our results of operations. It may in the future, however, increase the cost to acquire or replace property, plant and equipment and may increase the costs of labor and supplies. Our operating revenues and costs are influenced to a greater extent by commodity price changes. To the extent permitted by competition, regulation and our existing agreements, we have and will continue to pass along a portion of increased costs to our customers in the form of higher fees.

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ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

For certain of our activities, we are exposed to market risks related to the volatility of natural gas and NGL prices. To manage the impact of volatility from these prices, we utilize various exchange-traded and over-the-counter commodity financial instrument contracts. These contracts consist primarily of futures and swaps and are recorded at fair value in the consolidated balance sheets. In general, we use derivatives to reduce market exposure and price risk within our segments as follows:

- We use derivative financial instruments in connection with our natural gas inventory at the Bammel storage facility by purchasing physical natural gas and then selling forward financial contracts at a price sufficient to cover our carrying costs and provide a gross profit margin. We also use derivatives in our intrastate transportation and storage segment to hedge the sales price of retention natural gas in excess of consumption, a portion of volumes purchased at the wellhead from producers, and location price differentials related to the transportation of natural gas. Additionally, we use derivatives for trading purposes in this segment.
- Derivatives are utilized in our midstream segment in order to mitigate price volatility in our marketing activities and manage fixed price exposure incurred from contractual obligations.
- We also use derivative swap contracts to mitigate risk from price fluctuations on NGLs we retain for fees in our midstream segment.
- Our propane segment permitted customers to guarantee the propane delivery price for the next heating season. We executed fixed sales price contracts with our customers and entered into propane futures contracts to fix the purchase price related to these sales contracts, thereby locking in a gross profit margin. We used propane futures contracts to secure the purchase price of our propane inventory for a percentage of our anticipated propane sales.
- In our Other segment, we utilized derivatives for trading purpose, primarily in the electricity markets.

The market prices used to value our financial derivatives and related transactions have been determined using independent third party prices, readily available market information, broker quotes and appropriate valuation techniques.

If we designate a derivative financial instrument as a cash flow hedge and it qualifies for hedge accounting, the change in the fair value is deferred in AOCI until the underlying hedged transaction occurs. Any ineffective portion of a cash flow hedge's change in fair value is recognized each period in earnings. Gains and losses deferred in AOCI related to cash flow hedges remain in AOCI until the underlying physical transaction occurs, unless it is probable that the forecasted transaction will not occur by the end of the originally specified time period or within an additional two-month period of time thereafter. For financial derivative instruments that do not qualify for hedge accounting, the change in fair value is recorded in cost of products sold in the consolidated statements of operations.

If we designate a hedging relationship as a fair value hedge, we record the changes in fair value of the hedged asset or liability in cost of products sold in our consolidated statement of operations. This amount is offset by the changes in fair value of the related hedging instrument. Any ineffective portion or amount excluded from the assessment of hedge ineffectiveness is also included in cost of products sold in our consolidated statements of operations.

We use futures and basis swaps, designated as fair value hedges, to hedge our natural gas inventory stored in our Bammel storage facility. Changes in the spreads between the forward natural gas prices designated as fair value hedges and the physical Bammel inventory spot price result in unrealized gains or losses until the underlying physical gas is withdrawn and the related designated 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.

We attempt to maintain balanced positions to protect ourselves from the volatility in the energy commodities markets; however, net unbalanced positions can exist. Long-term physical contracts are tied to index prices. System gas, which is also tied to index prices, is expected to provide most of the gas required by our long-term physical contracts. When third-party gas is required to supply long-term contracts, a hedge is put in place to protect the margin on the contract. To the extent open commodity positions exist, fluctuating commodity prices can impact our financial position and results of operations, either favorably or unfavorably.

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The table below summarizes our commodity-related financial derivative instruments and fair values, including derivatives related to our consolidated subsidiaries, as well as the effect of an assumed hypothetical 10% change in the underlying price of the commodity. Notional volumes are presented in MMBtu for natural gas, thousand megawatt for power, gallons for propane and barrels for natural gas liquids and refined products. Dollar amounts are presented in millions.

	December 31, 2012			December 31, 2011		
	Notional Volume	Fair Value Asset (Liability)	Effect of Hypothetical 10% Change	Notional Volume	Fair Value Asset (Liability)	Effect of Hypothetical 10% Change
Mark-to-Market Derivatives						
(Trading)						
Natural Gas:						
Basis Swaps IFERC/NYMEX [1]	(30,980,000)	$(6)	$—	(151,260,000)	$(23)	$3
Power:						
Forwards	19,650	—	1	—	—	—
Futures	(1,509,300)	(1)	1	—	—	—
Options – Calls	1,656,400	2	1	—	—	—
(Non-Trading)						
Natural Gas:						
Basis Swaps IFERC/NYMEX	150,000	(1)	—	(61,420,000)	4	—
Swing Swaps IFERC	(83,292,500)	1	1	92,370,000	(1)	—
Fixed Swaps/Futures	27,077,500	(7)	9	797,500	(4)	—
Forward Physical Contracts	11,689,855	—	2	(10,672,028)	—	1
Natural Gas Liquid:						
Forwards/Swaps	(30,000)	—	—	—	—	—
Refined Products	(666,000)	(3)	14	—	—	—
Propane:						
Forwards/Swaps	—	—	—	38,766,000	(4)	5
Fair Value Hedging Derivatives						
(Non-Trading)						
Natural Gas:						
Basis Swaps IFERC/NYMEX	(18,655,000)	(1)	—	(28,752,500)	(1)	—
Fixed Swaps/Futures	(44,272,500)	4	15	(45,822,500)	71	14
Cash Flow Hedging Derivatives						
(Non-Trading)						
Natural Gas:						
Fixed Swaps/Futures	(8,212,500)	(3)	3	—	—	—
Options – Puts	—	—	—	3,600,000	6	1
Options – Calls	—	—	—	(3,600,000)	—	—
Natural Gas Liquid:						
Forwards/Swaps	(930,000)	(2)	7	—	—	—
Refined Products	(98,000)	—	1	—	—	—

(1) Includes aggregate amounts for open positions related to Houston Ship Channel, Waha Hub, NGPL TexOk, West Louisiana Zone and Henry Hub locations.

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

Interest Rate Risk

As of December 31, 2012, we had $2.21 billion of floating rate debt outstanding. A hypothetical change of 100 basis points would result in a change to interest expense of $22 million annually. We manage a portion of our interest rate exposure by utilizing interest rate swaps. To the extent that we have debt with floating interest rates that are not hedged, our results of operations, cash flows and financial condition could be adversely affected by increases in interest rates.

We had the following interest rate swaps outstanding as of December 31, 2012 (dollars in millions), none of which are designated as hedges for accounting purposes:

Entity	Term	Type [1]	Notional Amount Outstanding December 31, 2012	Notional Amount Outstanding December 31, 2011
ETP	May 2012[2]	Forward starting to pay a fixed rate of 2.59% and receive a floating rate	$—	$350
ETP	August 2012[2]	Forward starting to pay a fixed rate of 3.51% and receive a floating rate	—	500
ETP	July 2013[2]	Forward starting to pay a fixed rate of 4.02% and receive a floating rate	400	300
ETP	July 2014[2]	Forward starting to pay a fixed rate of 4.25% and receive a floating rate	400	—
ETP	July 2018	Pay a floating rate plus a spread of 4.17% and receive a fixed rate of 6.70%	600	500
Southern Union	November 2016	Pay a fixed rate of 2.91% and receive a floating rate	75	—
Southern Union	November 2021	Pay a fixed rate of 3.75% and receive a floating rate	450	—

(1) As of December 31, 2011, floating rates are based on 3-month LIBOR.

(2) Represents the effective date. These forward starting swaps have a term of 10 years with a mandatory termination date the same as the effective date.

A hypothetical change of 100 basis points in interest rates for these interest rate swaps would result in a net change in the fair value of interest rate derivatives and earnings (recognized in gains and losses on non-hedged interest rate derivatives) of approximately $52 million as of December 31, 2012. For the $600 million of interest rate swaps whereby we pay a floating rate and receive a fixed rate, a hypothetical change of 100 basis points in interest rates would result in a net change in annual cash flows (swap settlements) of $6 million. For the forward-starting interest rate swaps, a hypothetical change of 100 basis points in interest rates would not affect cash flows until the swaps are settled. For Southern Union's fixed to floating interest rate swaps, a hypothetical change of 100 basis points in interest rates would result in a net change in annual cash flows (swap settlements) of $7 million.

Credit Risk

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

For financial instruments, failure of a counterparty to perform on a contract could result in our inability to realize amounts that have been recorded on our consolidated balance sheet and recognized in net income or other comprehensive income.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

An evaluation was performed under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer of our General Partner, of the effectiveness of the design and operation of our disclosure controls and procedures (as such terms are defined in Rules 13a–15(e) and 15d–15(e) of the Exchange Act) as of the end of the period covered by this report. Based upon that evaluation, management, including the Chief Executive Officer and Chief Financial Officer of our General Partner, concluded that our disclosure controls and procedures were adequate and effective as of December 31, 2012.

Management's Report on Internal Control over Financial Reporting

The management of Energy Transfer Partners, L.P. and subsidiaries is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer of our General Partner, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO framework").

On October 5, 2012, Sam Acquisition Corporation, a Pennsylvania corporation and a wholly-owned subsidiary of ETP, completed its merger with Sunoco, Inc. ("Sunoco"). Immediately following the closing of the Sunoco Merger, ETE contributed its interest in Southern Union into ETP Holdco Corporation ("Holdco"), an ETP-controlled entity. Management has acknowledged that it is responsible for establishing and maintaining a system of internal controls over financial reporting for Sunoco. We are in the process of integrating Sunoco, and we therefore excluded Sunoco from our December 31, 2012 assessment of the effectiveness of internal control over financial reporting. Sunoco had total assets of $4.51 billion at December 31, 2012 and third party revenue of $5.93 billion from October 5, 2012 to December 31, 2012 included in our consolidated financial statements as of and for the year ended December 31, 2012. The impact of the Sunoco transaction has not materially affected and is not expected to materially affect our internal control over financial reporting. As a result of these integration activities, certain controls will be evaluated and may be changed. We believe, however, that we will be able to maintain sufficient controls over the substantive results of our financial reporting throughout this integration process.

Our assessment of internal control over financial reporting did include assessments of Sunoco Logistics and Southern Union, both of which ETP obtained control of in connection with the Sunoco Merger and Holdco Transaction.

Based on our evaluation under the COSO framework, our management concluded that our internal control over financial reporting was effective as of December 31, 2012.

Grant Thornton LLP, an independent registered public accounting firm, has audited the effectiveness of our internal control over financial reporting as of December 31, 2012, as stated in their report, which is included herein.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Partners
Energy Transfer Partners, L.P.

We have audited the internal control over financial reporting of Energy Transfer Partners, L.P. (a Delaware limited partnership) and subsidiaries (the "Partnership") as of December 31, 2012, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Partnership's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Partnership's internal control over financial reporting based on our audit. Our audit of, and opinion on, the Partnership's internal control over financial reporting does not include the internal control over financial reporting of Sunoco, Inc., a consolidated subsidiary, whose financial statements reflect total assets and revenues constituting 10 and 38 percent, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2012. As indicated in Management's Report on Internal Control over Financial Reporting, Sunoco, Inc. was acquired during 2012, and therefore, management's assertion on the effectiveness of the Partnership's internal control over financial reporting excluded internal control over financial reporting of Sunoco, Inc. We did not audit the internal control over financial reporting of Sunoco Logistics Partners L.P., a consolidated subsidiary, whose financial statements as of December 31, 2012 and for the period from October 5, 2012 to December 31, 2012 reflect total assets and revenues constituting 24 and 20 percent, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2012. Sunoco Logistics Partners L.P.'s internal control over financial reporting was audited by other auditors whose report has been furnished to us, and our opinion, insofar as it relates to Sunoco Logistics Partners L.P.'s internal control over financial reporting in relation to the Partnership taken as a whole, is based solely on the report of the other auditors.

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

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

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

In our opinion, based on our audit and the report of the other auditors, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on criteria established in Internal Control-Integrated Framework issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements of the Partnership as of and for the year ended December 31, 2012, and our report dated March 1, 2013 expressed an unqualified opinion on those financial statements.

/s/ GRANT THORNTON LLP
Dallas, Texas
March 1, 2013

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Changes in Internal Control over Financial Reporting

There has been no change in our internal control over financial reporting (as defined in Rules 13a–15(f) or Rule 15d–15(f)) that occurred in the three months ended December 31, 2012 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

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PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Board of Directors

Our General Partner manages and directs all of our activities. The activities of our General Partner are managed and directed by its general partner, ETP LLC. Our officers and directors are officers and directors of ETP LLC. ETE, as the sole member of ETP LLC, is entitled under the limited liability company agreement of ETP LLC to appoint all of the directors of ETP LLC. This agreement provides that the Board of Directors of ETP LLC shall consist of not more than 13 persons, at least three of whom are required to qualify as independent directors. Our six current directors include ETP LLC’s Chief Executive Officer and ETP LLC’s President and Chief Operating Officer.

As of December 31, 2012, our Board of Directors was comprised of six persons, four of whom qualified as “independent” under the NYSE’s corporate governance standards. We have determined that Messrs. Byrne, Collins, Glaske, and Grimm all meet the NYSE’s independence requirements.

As a limited partnership, we are not required by the rules of the NYSE to seek unitholder approval for the election of any of our directors. We believe that ETE has appointed as directors individuals with experience, skills and qualifications relevant to the business of the Partnership, such as experience in energy or related industries or with financial markets, expertise in natural gas operations or finance, and a history of service in senior leadership positions. We do not have a formal process for identifying director nominees, nor do we have a formal policy regarding consideration of diversity in identifying director nominees, but we believe ETE has endeavored to assemble a group of individuals with the qualities and attributes required to provide effective oversight of the Partnership.

Board Leadership Structure. We have no policy requiring either that the positions of the Chairman of the Board and the Chief Executive Officer, or CEO, be separate or that they be occupied by the same individual. The Board of Directors believes that this issue is properly addressed as part of the succession planning process and that a determination on this subject should be made when it elects a new chief executive officer or at such other times as when consideration of the matter is warranted by circumstances. Currently, the Board of Directors believes that the CEO is best situated to serve as Chairman because he is the director most familiar with the Partnership’s business and industry, and most capable of effectively identifying strategic priorities and leading the discussion and execution of strategy. Independent directors and management have different perspectives and roles in strategy development. Our independent directors bring experience, oversight and expertise from outside the Partnership and from a variety of industries, while the CEO brings extensive experience and expertise related to the Partnership’s business. The Board of Directors believes that the current combined role of Chairman and CEO promotes strategy development and execution, and facilitates information flow between management and the Board of Directors, which are essential to effective governance.

One of the key responsibilities of the Board of Directors is to develop strategic direction and hold management accountable for the execution of strategy once it is developed. The Board of Directors believes the current combined role of Chairman and CEO, together with a majority of independent board members, is in the best interest of Unitholders because it provides the appropriate balance between strategy development and independent oversight of management.

Risk Oversight. Our Board of Directors generally administers its risk oversight function through the board as a whole. Our CEO, who reports to the Board of Directors, and the other executive officers, who report to our CEO, have day-to-day risk management responsibilities. Each of these executives attends the meetings of our Board of Directors, where the Board of Directors routinely receives reports on our financial results, the status of our operations, and other aspects of implementation of our business strategy, with ample opportunity for specific inquiries of management. In addition, at each regular meeting of the Board, management provides a report of the Partnership’s financial and operational performance, which often prompts questions or feedback from the Board of Directors. The Audit Committee provides additional risk oversight through its quarterly meetings, where it receives a report from the Partnership’s internal auditor, who reports directly to the Audit Committee, and reviews the Partnership’s contingencies with management and our independent auditors.

Corporate Governance

The Board of Directors has adopted both a Code of Business Conduct and Ethics applicable to our directors, officers and employees, and Corporate Governance Guidelines for directors and the Board. Current copies of our Code of Business Conduct and Ethics, Corporate Governance Guidelines and charters of the Audit and Compensation Committees of our Board of Directors are available on our website at www.energytransfer.com and will be provided in print form to any Unitholder requesting such information.

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Please note that the preceding Internet address is for information purposes only and is not intended to be a hyperlink. Accordingly, no information found and/or provided at such Internet addresses or at our website in general is intended or deemed to be incorporated by reference herein.

Annual Certification

We have filed the required certifications under Section 302 of the Sarbanes-Oxley Act of 2002 as Exhibits 31.1 and 31.2 to this annual report. In 2012, our CEO provided to the NYSE the annual CEO certification regarding our compliance with the NYSE corporate governance listing standards.

Conflicts Committee

Our Partnership Agreement provides that the Board of Directors may, from time to time, appoint members of the Board to serve on the Conflicts Committee with the authority to review specific matters for which the Board of Directors believes there may be a conflict of interest in order to determine if the resolution of such conflict proposed by the General Partner is fair and reasonable to the Partnership and its Unitholders. As a policy matter, the Conflicts Committee generally reviews any proposed related-party transaction that may be material to the Partnership to determine if the transaction presents a conflict of interest and whether the transaction is fair and reasonable to the Partnership. Pursuant to the terms of our partnership agreement, any matters approved by the Conflicts Committee will be conclusively deemed to be fair and reasonable to the Partnership, approved by all partners of the Partnership and not a breach by the General Partner or its Board of Directors of any duties they may owe the Partnership or the Unitholders.

Audit Committee

The Board of Directors has established an Audit Committee in accordance with Section 3(a)(58)(A) of the Exchange Act. The Board of Directors appoints persons who are independent under the NYSE's standards for audit committee members to serve on its Audit Committee. In addition, the Board determines that at least one member of the Audit Committee has such accounting or related financial management expertise sufficient to qualify such person as the audit committee financial expert in accordance with Item 407 (d)(5) of Regulation S-K. The Board has determined that based on relevant experience, Audit Committee members Paul E. Glaske and Bill W. Byrne qualified as Audit Committee financial experts during 2012. A description of the qualifications of Mr. Glaske and Mr. Byrne may be found elsewhere in this Item under "—Directors and Executive Officers of the General Partner."

The Audit Committee meets on a regularly scheduled basis with our independent accountants at least four times each year and is available to meet at their request. The Audit Committee has the authority and responsibility to review our external financial reporting, review our procedures for internal auditing and the adequacy of our internal accounting controls, consider the qualifications and independence of our independent accountants, engage and direct our independent accountants, including the letter of engagement and statement of fees relating to the scope of the annual audit work and special audit work which may be recommended or required by the independent accountants, and to engage the services of any other advisors and accountants as the Audit Committee deems advisable. The Audit Committee reviews and discusses the audited financial statements with management, discusses with our independent auditors matters required to be discussed by auditing standards, and makes recommendations to the Board of Directors relating to our audited financial statements. The Audit Committee periodically recommends to the Board of Directors any changes or modifications to its charter that may be required. The Board of Directors adopts the charter for the Audit Committee. Paul E. Glaske, Michael K. Grimm and Bill W. Byrne currently serve on the Audit Committee and Mr. Glaske serves as the chairman of the Audit Committee.

Compensation and Nominating/Corporate Governance Committees

Although we are not required under NYSE rules to appoint a Compensation Committee or a Nominating/Corporate Governance Committee because we are a limited partnership, our Board of Directors has established a Compensation Committee to establish standards and make recommendations concerning the compensation of our officers and directors. In addition, the Compensation Committee determines and establishes the standards for any awards to our employees and officers under the equity compensation plans adopted by our Unitholders, including the performance standards or other restrictions pertaining to the vesting of any such awards. Pursuant to the charter of the Compensation Committee, a director serving as a member of the Compensation Committee may not be an officer of or employed by the General Partner, the Partnership or its subsidiaries. Michael K. Grimm and Bill W. Byrne serve as

the members of the Compensation Committee and Mr. Grimm serves as the chairman of the Compensation Committee. Our General Partner has determined that both Messrs. Byrne and Grimm are "independent" (as that term is defined in the applicable NYSE corporate governance standards).
The Compensation Committee’s responsibilities include, among other duties, the following:
- annually review and approve goals and objectives relevant to compensation of the CEO, if applicable;

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- annually evaluate the CEO's performance in light of these goals and objectives, and make recommendations to the board of directors of our General Partner with respect to the CEO's compensation levels, if applicable, based on this evaluation;
- based on input from, and discussion with, the CEO, make recommendations to the board of directors of our General Partner with respect to non-CEO executive officer compensation, including incentive compensation and compensation under equity- based plans;
- make determinations with respect to the grant of equity-based awards to executive officers under our equity incentive plans;
- periodically evaluate the terms and administration of ETP's short-term and long-term incentive plans to assure that they are structured and administered in a manner consistent with ETP's goals and objectives;
- periodically evaluate incentive compensation and equity-related plans and consider amendments, if appropriate;
- periodically evaluate the compensation of the directors;
- retain and terminate any compensation consultant to be used to assist in the evaluation of director, CEO or executive officer compensation; and
- perform other duties as deemed appropriate by the board of directors of our General Partner.

Matters relating to the nomination of directors or corporate governance matters are addressed to and determined by the full Board of Directors.

Code of Business Conduct and Ethics

The Board of Directors has adopted a Code of Business Conduct and Ethics applicable to our officers, directors and employees. Specific provisions are applicable to the principal executive officer, principal financial officer, principal accounting officer and controller, or those persons performing similar functions, of our General Partner. Amendments to, or waivers from, the Code of Business Conduct and Ethics will be available on our website and reported as may be required under SEC rules. Any technical, administrative or other non-substantive amendments to the Code of Business Conduct and Ethics may not be posted.

Meetings of Non-management Directors and Communications with Directors

Our non-management directors meet in regularly scheduled sessions. The Chairman of each of our Audit and Compensation Committee alternate as the presiding director of such meetings.

We have established a procedure by which Unitholders or interested parties may communicate directly with the Board of Directors, any committee of the Board, any independent directors, or any one director serving on the Board of Directors by sending written correspondence addressed to the desired person or entity to the attention of our General Counsel at Energy Transfer Partners, L.P., 3738 Oak Lawn Avenue, Dallas, Texas 75219 or generalcounsel@energytransfer.com. Communications are distributed to the Board of Directors, or to any individual director or directors as appropriate, depending on the facts and circumstances outlined in the communication.

Directors and Executive Officers of the General Partner

The following table sets forth certain information with respect to the executive officers and members of the Board of Directors of our General Partner as of February 28, 2013. Executive officers and directors are elected for one-year terms.

Name	Age	Position with Our General Partner
Kelcy L. Warren	57	Chief Executive Officer and Chairman of the Board of Directors
Marshall S. (Mackie) McCrea, III	53	President, Chief Operating Officer and Director
Martin Salinas, Jr.	41	Chief Financial Officer
Thomas P. Mason	56	Senior Vice President, General Counsel and Secretary
Richard Cargile	53	President of Midstream Operations
Bill W. Byrne	83	Director
Paul E. Glaske	79	Director
Ted Collins, Jr.	74	Director
Michael K. Grimm	58	Director

Messrs. Warren and McCrea also serve as directors of ETE's general partner.

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Set forth below is biographical information regarding the foregoing officers and directors of our General Partner:
Kelcy L. Warren. Mr. Warren is the Chief Executive Officer and Chairman of the Board of our General Partner and has served in that capacity since August 2007. Prior to that, Mr. Warren had served as the Co-Chief Executive Officer and Co-Chairman of the Board of our General Partner since the combination of the midstream and intrastate transportation and storage operations of ETC OLP and the retail propane operations of HOLP in January 2004. Prior to the combination of the operations of ETC OLP and HOLP, Mr. Warren served as President of the general partner of ET Company I, Ltd., having served in that capacity since 1996. From 1996 to 2000, he also served as a director of Crosstex Energy, Inc. From 1993 to 1996, he served as President, Chief Operating Officer and a Director of Cornerstone Natural Gas, Inc. Mr. Warren has more than 25 years of business experience in the energy industry. The Board of Directors selected Mr. Warren to serve as a director and as Chairman because he is the Partnership's Chief Executive Officer and has more than 25 years in the natural gas industry. Mr. Warren also has relationships with chief executives and other senior management at natural gas transportation companies throughout the United States, and brings a unique and valuable perspective to the Board of Directors.
Marshall S. (Mackie) McCrea, III. Mr. McCrea was appointed as a director on December 23, 2009. He is the President and Chief Operating Officer of our General Partner and has served in that capacity since June 2008. Prior to that, he served as President – Midstream of our General Partner from March 2007 to June 2008. Previously he served as the Senior Vice President – Commercial Development since the combination of the operations of ETC OLP and HOLP in January 2004. In March 2005, Mr. McCrea was named president of ETC OLP. Prior to the combination of the operations of ETC OLP and HOLP, Mr. McCrea served as Senior Vice President – Business Development and Producer Services of the general partner of ETC OLP and ET Company I, Ltd., having served in that capacity since 1997. Mr. McCrea also currently serves on the Board of Directors of the general partner of ETE and of Sunoco Logistics. The Board of Directors selected Mr. McCrea to serve as a director because he serves as our President and Chief Operating Officer and brings extensive project development and operational experience to the Board. He has held various positions in the natural gas business over the past 25 years and is able to assist the Board of Directors in creating and executing the Partnership's strategic plan.
Martin Salinas, Jr. Mr. Salinas has served as Chief Financial Officer of our General Partner since June 2008. Mr. Salinas had previously served as our Controller and Treasurer from September 2004 to June 2008. Prior to joining ETP, Mr. Salinas was a Senior Audit Manager with KPMG in San Antonio, Texas from September 2002. Mr. Salinas also serves on the Board of Directors of the general partner of Sunoco Logistics.
Thomas P. Mason. Mr. Mason has served as Senior Vice President, General Counsel and Secretary of our General Partner since April 2012. Mr. Mason previously served as Vice President, General Counsel and Secretary from June 2008 and as General Counsel and Secretary of our General Partner from February 2007. Prior to joining ETP, he was a partner in the Houston office of Vinson & Elkins. Mr. Mason has specialized in securities offerings and mergers and acquisitions for more than 25 years. Mr. Mason also serves on the Board of Directors of the general partner of Sunoco Logistics.
Richard Cargile. Mr. Cargile joined ETP in March 2012 and serves as President of Midstream Operations. Mr. Cargile joined ETP with over 30 years of midstream experience, most recently serving as President of DCP Midstream's Southern Business Unit.
Bill W. Byrne. Mr. Byrne is the principal of Byrne & Associates, LLC, an investment company based in Tulsa, Oklahoma. Prior to his retirement in 1992, Mr. Byrne was Vice President of Warren Petroleum Company, the natural gas liquids division of Chevron Corporation. Mr. Byrne has previously held executive positions with Gulf Oil Corporation and Empire Energy Corporation. He was also a member of Empire's Board of Directors. Mr. Byrne has served as a director of our General Partner since 1992 and is a member of both the Audit Committee and the Compensation Committee. Mr. Byrne is a former president and director of the National Propane Gas Association ("NPGA"). The Board of Directors selected Mr. Byrne to serve as a director based on his significant industry expertise.
Paul E. Glaske. Mr. Glaske retired as Chairman and Chief Executive Officer of Blue Bird Corporation, the largest manufacturer of school buses with manufacturing plants in three countries. Prior to becoming president of Blue Bird in 1986, Mr. Glaske served as the president of the Marathon LeTourneau Company, a manufacturer of large off-road mining and material handling equipment and off-shore drilling rigs. He served as a member of the board of directors

of BorgWarner, Inc. of Chicago, Illinois until April 2008. Currently, Mr. Glaske serves on the board of directors of both Lincoln Educational Services in New Jersey, and Camcraft, Inc., in Illinois. Mr. Glaske has served as a director of our General Partner since February 2004 and is chairman of the Audit Committee. The Board selected Mr. Glaske to serve as a director because it believes he is familiar with running a company from the field level to the boardroom based on his previous experience. As a former CEO and director at various other companies, Mr. Glaske has been involved in succession planning, compensation, employee management and the evaluation of acquisition opportunities.

Ted Collins, Jr. Mr. Collins has been an independent oil and gas producer since 2000. He is also chairman and chief executive officer of Patriot Resources Partners LLC and a director of CLL Global Research Foundation. Mr. Collins previously served as

President of Collins & Ware Inc. from 1988 to 2000, when its assets were sold to Apache Corporation. From 1982 to 1988, Mr. Collins was President of EOG Resources, and its predecessors, Enron Oil and Gas Company, HNG Oil Company and HNG Internorth Exploration Co. From 1969 to 1982, Mr. Collins served as Executive Vice President of American Quasar Petroleum Company. In February 2011, Mr. Collins was elected as a director of Oasis Petroleum, Inc. and has served on its audit committee and nominating and governance committee since May 2011. Mr. Collins has served as a director of our General Partner since August 2004. Mr. Collins is a past President of the Permian Basin Petroleum Association, the Permian Basin Landmen's Association, the Petroleum Club of Midland and has served as Chairman of the Midland Wildcat Committee since 1984. The Board selected Mr. Collins to serve as a director because of his previous experience as an executive in various positions in the oil and gas industry. In addition, as a public company director at various other companies, Mr. Collins has been involved in succession planning, compensation, employee management and the evaluation of acquisition opportunities.

Michael K. Grimm. Mr. Grimm is one of the original founders of Rising Star Energy, L.L.C., a privately held upstream exploration and production company active in onshore continental United States, and has served as its President and Chief Executive Officer since 1995. Currently, Mr. Grimm is also President of Rising Star Energy Development Company and a co-CEO of RSP Permian, which is active in the drilling and developing of West Texas Permian Basin oil reserves. Prior to the formation of the first Rising Star companies, Mr. Grimm was Vice President of Worldwide Exploration and Land for Placid Oil Company from 1990 to 1994. Prior to joining Placid Oil Company, Mr. Grimm was employed by Amoco Production Company for 13 years where he held numerous positions throughout the exploration department in Houston, New Orleans and Chicago. Mr. Grimm has been an active member of the Independent Petroleum Association of America, the American Association of Professional Landmen, Dallas Producers Club, Dallas Wildcat Committee, and Fort Worth Wildcatters. Mr. Grimm has served as a director of our General Partner since December 2005 and is a member of the Audit Committee and chairman of the Compensation Committee. The Board selected Mr. Grimm to serve as a director because of his extensive experience in the energy industry and his service as a senior executive at several energy-related companies, in addition to his contacts in the industry gained through his involvement in energy-related organizations.

Compensation of the General Partner

Our General Partner does not receive any management fee or other compensation in connection with its management of the Partnership and the Operating Companies. Our General Partner and its affiliates performing services for the Partnership and the Operating Companies are reimbursed at cost for all expenses incurred on behalf of the Partnership, including the costs of employee compensation allocable to, but not paid directly by, the Partnership, if any, and all other expenses necessary or appropriate to the conduct of the business of, and allocable to, the Partnership. Following the combination of the operations of ETC OLP and HOLP in January 2004, the employees of the General Partner became employees of our Operating Companies, and thus, our General Partner has not incurred additional reimbursable costs since that time.

Our General Partner is ultimately controlled by the general partner of ETE, which general partner entity is partially-owned by certain of our current and prior named executive officers. We pay quarterly distributions to our General Partner in accordance with our Partnership Agreement with respect to its ownership of a general partner interest and the incentive distribution rights specified in our Partnership Agreement. The amount of each quarterly distribution that we must pay to our General Partner is based solely on the provisions of our Partnership Agreement, which agreement specifies the amount of cash we distribute to our General Partner based on the amount of cash that we distribute to our limited partners each quarter. Accordingly, the cash distributions we make to our General Partner bear no relationship to the level or components of compensation of our General Partner's executive officers. Our General Partner's distribution rights are described in detail in Note 6 to our consolidated financial statements. Our named executive officers also own directly and indirectly certain of our limited partner interests and, accordingly, receive quarterly distributions. Such per unit distributions equal the per unit distributions made to all our limited partners and bear no relationship to the level of compensation of the named executive officers.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires our officers and directors, and persons who own more than 10% of a registered class of our equity securities, to file reports of beneficial ownership and changes in beneficial ownership

with the SEC. Officers, directors and greater than 10% Unitholders are required by SEC regulations to furnish the General Partner with copies of all Section 16(a) forms.
Based solely on our review of the copies of such forms received by us, or written representations from reporting persons, we believe that during the year ended December 31, 2012, all filing requirements applicable to our officers, directors, and greater than 10% beneficial owners were met in a timely manner.

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ITEM 11. EXECUTIVE COMPENSATION

Overview

As a limited partnership, we are managed by our General Partner, which in turn is managed by its general partner, ETP LLC, which we refer to in this Item as "our General Partner." As of December 31, 2012 ETE owned 100% of our General Partner and approximately 17% of our outstanding units. All of our employees are employed by and receive employee benefits from our Operating Companies.

Compensation Discussion and Analysis

Named Executive Officers

We do not have officers or directors. Instead, we are managed by the board of directors of our General Partner, and the executive officers of our General Partner perform all of our management functions. As a result, the executive officers of our General Partner are essentially our executive officers, and their compensation is administered by our General Partner. This Compensation Discussion and Analysis is, therefore, focused on the total compensation of the executive officers of our General Partner as set forth below. The executive officers we refer to in this discussion as our "named executive officers" are the following officers of our General Partner:

- Kelcy L. Warren, Chief Executive Officer;
- Marshall S. (Mackie) McCrea, III, President and Chief Operating Officer;
- Martin Salinas, Jr., Chief Financial Officer;
- Thomas P. Mason, Senior Vice President, General Counsel and Secretary; and
- Richard Cargile, President - Midstream.

Our General Partner's Philosophy for Compensation of Executives

In general, our General Partner's philosophy for executive compensation is based on the premise that a significant portion of each executive's compensation should be incentive-based and that executives' base salary levels should be competitive in the marketplace for executive talent and abilities. Our General Partner also believes the incentives should be competitive in the marketplace and balanced between short and long-term performance. Our General Partner believes this balance is achieved by (i) the payment of annual discretionary cash bonuses that consider the achievement of the Partnership's financial performance objectives for a fiscal year set at the beginning of such fiscal year and the individual contributions of our named executive officers to the success of the Partnership and (ii) the annual grant of restricted unit awards under our equity incentive plans, which are intended to provide a longer term incentive to our key employees to focus their efforts on increasing the market price of our publicly traded units and to increase the cash distribution we pay to our Unitholders.

Prior to December 2012, our equity awards were primarily in the form of restricted unit awards that vest over a specified time period, with substantially all of these awards vesting over a five-year period at 20% per year based on continued employment through each specified vesting date. Beginning in December 2012, we began granting restricted unit awards that vest, based upon continued employment, at a rate of 60% after the third year of service and the remaining 40% after the fifth year of service. Our General Partner believes that these equity-based incentive arrangements are important in attracting and retaining our executive officers and key employees as well as motivating these individuals to achieve our business objectives. The equity-based compensation also reflects the importance we place on aligning the interests of our named executive officers with those of our Unitholders.

While we are responsible for the direct payment of the compensation of our named executive officers as employees of ETP, ETP does not participate or have any input in any decisions as to the compensation policies of our General Partner or the compensation levels of the executive officers of our General Partner. The compensation committee of the board of directors of our General Partner (the "Compensation Committee") is responsible for the approval of the compensation policies and the compensation levels of these executive officers. We directly pay these executive officers in lieu of receiving an allocation of overhead related to executive compensation from our General Partner. For the year ended December 31, 2012, we paid 100% of the compensation of the executive officers of our General Partner as we represent the only business currently managed by our General Partner.

For a more detailed description of the compensation of our named executive officers, please see "— Compensation Tables" below.

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Compensation Philosophy

Our compensation program is structured to provide the following benefits:

- attract, retain and reward talented executive officers and key management employees by providing total compensation competitive with that of other executive officers and key management employees employed by publicly traded limited partnerships of similar size and in similar lines of business;
- motivate executive officers and key employees to achieve strong financial and operational performance;
- emphasize performance-based compensation; and
- reward individual performance.

Components of Executive Compensation

For the year ended December 31, 2012, the compensation paid to our named executive officers, other than our CEO, consisted of the following components:

- annual base salary;
- non-equity incentive plan compensation consisting solely of discretionary cash bonuses;
- vesting of previously issued equity-based awards issued pursuant to our equity incentive plans;
- compensation resulting from the vesting of equity issuances made by an affiliate; and
- 401(k) plan contributions.

Mr. Warren, our CEO, has voluntarily elected not to accept any salary, bonus or equity incentive compensation (other than a salary of $1.00 per year plus an amount sufficient to cover his allocated payroll deductions for health and welfare benefits).

Methodology

The Compensation Committee considers relevant data available to it to assess the competitive position with respect to base salary, annual short-term incentives and long-term incentive compensation for our executive officers. The Compensation Committee also considers individual performance, levels of responsibility, skills and experience. Periodically, the Compensation Committee engages a third-party consultant to provide market information for compensation levels at peer companies in order to assist the Compensation Committee in its determination of compensation levels for our executive officers. Most recently, the Compensation Committee engaged Mercer Consulting Services ("Mercer") during the year ended December 31, 2010 to assist in the determination of compensation levels for our senior management. The results of this study were utilized to determine long-term incentive awards and bonuses during 2012, 2011 and 2010. The consultant provided an analysis of compensation for senior executives at the following 15 companies in the energy industry, comprised primarily of midstream and exploration and production companies:

- Enterprise Products Partners L.P.
- Plains All American Pipeline, L.P.
- CenterPoint Energy, Inc.
- The Williams Companies, Inc.
- Sempra Energy
- Kinder Morgan Energy Partners, L.P.
- ONEOK Partners, L.P.
- Enbridge Energy Partners, L.P.
- Sunoco Logistics Partners L.P.
- Atmos Energy Corporation
- El Paso Corporation
- Spectra Energy Partners, LP
- Targa Resources Partners LP
- NuStar Energy L.P.
- Southern Union Company

The compensation analysis provided by Mercer covered annual salary, annual cash bonus and long-term incentive arrangements for the senior executives of these companies. The Compensation Committee utilized the information provided by Mercer to compare the levels of base salary, annual bonus and long-term equity incentives at these other companies with those of our named executive officers to ensure that compensation of our named executive officers is competitive with the compensation for executive officers of these other companies. The Compensation Committee did not attempt to benchmark the base salary, annual bonus or long-term equity incentives to any percentage of, or numerical average of, the compensation levels at these other companies. Mercer did not provide any non-executive compensation services for the Partnership during 2012, 2011 or 2010.

Base Salary. As discussed above, the base salaries of our named executive officers are determined by the Compensation Committee after taking into account the recommendations of Mr. Warren. For 2012, the Compensation

Committee approved an increase of 19% to Mr. McCrea's annual base salary, 18% to Mr. Salinas' annual base salary, and 16% to Mr. Mason's annual base salary. The

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Compensation Committee determined that such increases were warranted based on the factors described below under "-Annual Bonus." The Compensation Committee also deemed the increases to be reasonable in light of the expanded roles that each of the individuals serves with respect to the consolidated organization subsequent to the Citrus, Sunoco and Holdco transactions in 2012. The Compensation Committee did not increase the base salary of Mr. Cargile given his employment with the Partnership began in 2012.

Annual Bonus. In addition to base salary, the Compensation Committee makes a determination whether to award our named executive officers, other than our CEO (who has voluntarily elected to forgo any annual bonuses), discretionary annual cash bonuses following the end of the year. These discretionary bonuses, if awarded, are intended to reward our named executive officers for the achievement of financial performance objectives during the year for which the bonuses are awarded in light of the contribution of each individual to our profitability and success during such year. In this regard, the Compensation Committee takes into account whether the Partnership achieved or exceeded its internal EBITDA budget for the year, which is approved by the board of directors of our General Partner as discussed below, as an important element in making its determinations with respect to annual bonuses. The Compensation Committee also considers the recommendation of our CEO in determining the specific annual cash bonus amounts for each of the other named executive officers. The Compensation Committee does not establish its own financial performance objectives in advance for purposes of determining whether to approve any annual bonuses, and the Compensation Committee does not utilize any formulaic approach to determine annual bonuses.

The Partnership's internal financial budgets are generally developed for each business segment, and then aggregated with appropriate corporate level adjustments, to reflect an overall performance objective that is reasonable in light of market conditions and opportunities based on a high level of effort and dedication across all segments of the Partnership's business. The evaluation of the Partnership's performance versus its internal financial budget is based on the Partnership's EBITDA for a calendar year. In general, the Compensation Committee believes that Partnership performance at or above the internal EBITDA budget would support bonuses to our named executive officers ranging from 100% to 120% of their annual salary. The individual bonus amounts for each named executive officer, other than our CEO, also reflect the Compensation Committee's view of the impact of such individual's efforts and contributions towards (i) achievement of the Partnership's success in exceeding its internal financial budget, (ii) the development of new projects that are expected to result in increased cash flows from operations in future years, (iii) the completion of mergers, acquisitions or similar transactions that are expected to be accretive to the Partnership and increase distributable cash flow, and (iv) the overall management of the Partnership's business.

In February 2013, the Compensation Committee approved cash bonuses relating to the 2012 calendar year to Messrs. McCrea, Salinas, Mason and Cargile of $700,000, $375,000, $500,000 and $230,000, respectively. In approving the cash bonuses for Messrs. McCrea, Salinas, Mason and Cargile, the Compensation Committee took into account the achievement by the Partnership of approximately 95% of its internal EBITDA budget of $2.75 billion for 2012 as well as the individual performances of these individuals with respect to promoting the Partnership's financial, strategic and operating objectives for 2012. The cash bonuses for Messrs. Salinas and Cargile were consistent with the target. Mr. McCrea and Mr. Mason's cash bonuses exceeded target amounts by 7% and 13%, respectively. With respect to Mr. McCrea, the Compensation Committee noted his leadership in the successful development of several significant internal growth projects, including (i) the early completion of Lone Star's West Texas Gateway NGL pipeline with estimated capital expenditures of approximately $917 million, (ii) the completion of Lone Star's first NGL fractionation facility at Mont Belvieu, Texas with estimated capital expenditures of $390 million and the negotiation of multiple long-term agreements to support Lone Star's planned construction of a second fractionation facility, (iii) the negotiation of long-term commitments from producers to support the planned further expansion of our REM pipeline project and the construction of a new processing facility in the Eagle Ford Shale in South Texas that was placed in service in December 2012. In addition, the Compensation Committee recognized the increased scope of Mr. McCrea's responsibilities following the acquisitions of Southern Union and Sunoco in 2012. With respect to Mr. Mason, the Compensation Committee took note of his key roles in (i) successfully consummating the acquisition by ETE of Southern Union and ETP's acquisition of a 50% interest in Citrus Corp., (ii) effectively negotiating and consummating the merger of Sunoco and ETP and the related contribution by ETE of its interest in Southern Union, and by ETP of its interest in Sunoco, to ETP Holdco, (iii) overseeing the successful negotiation of agreements to sell

Southern Union's Missouri Gas Energy and New England Gas Company divisions to the Laclede Entities for $1.035 billion and (iv) effectively managing of the legal functions for ETE and ETP, as well as Southern Union and Sunoco as part of the ongoing integration of those companies into Energy Transfer.

Equity Awards. Each of our 2004 Unit Plan and 2008 Incentive Plan authorizes the Compensation Committee, in its discretion, to grant awards of restricted units, unit options and other awards related to our units upon such terms and conditions as it may determine appropriate and in accordance with general guidelines as defined by each such plan. The Compensation Committee determined and/or approved the terms of the unit grants awarded to our named executive officers, including the number of Common Units subject to the unit award and the vesting structure of those unit awards. All of the awards granted to the named executive officers under these equity incentive plans have consisted of restricted unit awards, which have required the achievement of certain performance objectives in order for the awards to become vested or restricted unit awards that are subject to vesting over a specified time period. Upon vesting of any unit award, ETP Common Units are issued.

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Commencing in 2008, all of the new unit awards granted have provided for vesting over a specified time period, with vesting based on continued employment as of each applicable vesting date, rather than vesting based on the satisfaction of any performance objectives. This change resulted from the Compensation Committee's determination that vesting based on continued employment, rather than the satisfaction of performance objectives, was more generally prevalent with companies in the energy industry. In January 2013, the Compensation Committee approved grants of unit awards to Messrs. McCrea, Salinas, Mason and Cargile of 33,333 units, 16,667 units, 30,000 units and 12,000 units, respectively. These unit awards provide for vesting over a five-year period, with 60% vesting at the end of the third year and the remaining 40% vesting at the end of the fifth year, subject to continued employment through each specified vesting date. Upon inception of his employment in March 2012, Mr. Cargile also received a grant of 18,000 units which vest ratably over five years.

These unit awards entitle the recipients of the unit awards to receive, with respect to each ETP Common Unit subject to such award that has not either vested or been forfeited, a cash payment equal to each cash distribution per Common Unit made by us on our Common Units promptly following each such distribution by us to our Unitholders. In approving the grant of such unit awards, the Compensation Committee took into account the same factors as discussed above under the caption "-Annual Bonus," the long-term objective of retaining such individuals as key drivers of the Partnership's future success, the existing level of equity ownership of such individuals and the previous awards to such individuals of equity unit awards subject to vesting.

The issuance of Common Units pursuant to our equity incentive plans is intended to serve as a means of incentive compensation; therefore, no consideration will be payable by the plan participants upon vesting and issuance of the Common Units.

The unit awards under our equity incentive plans generally require the continued employment of the recipient during the vesting period. The Compensation Committee has in the past and may in the future, but is not required to, accelerate the vesting of unvested unit awards in the event of the termination or retirement of an executive officer. The Compensation Committee did not accelerate the vesting of unit awards to any named executive officers in 2012.

Subsidiary Equity Awards. In addition to their roles as officers of our General Partner, Messrs. Salinas and McCrea also serve as officers and directors of the general partner of Sunoco Logistics. In connection with those roles at Sunoco Logistics' general partner, in January 2013, the compensation committee of Sunoco Logistics' general partner awarded Messrs. Salinas and McCrea time-based restricted units of Sunoco Logistics in the amount of 8,333 units and 16,667 units, respectively. These awards provide for vesting over a five-year vesting period at a rate of 20% per year, subject to continued employment. These awards have not been reflected in the compensation tables presented below, because the grant date occurred subsequent to December 31, 2012.

Affiliate Equity Awards. McReynolds Energy Partners, L.P., the general partner of which is owned and controlled by the President of ETE's general partner, has awarded to certain officers of ETP certain rights related to units of ETE previously issued by ETE to such officers. These rights include the economic benefits of ownership of these ETE units based on a five-year vesting schedule whereby the officer will vest in the ETE units at a rate of 20% per year. As these ETE units are conveyed to the recipients of these awards upon vesting from a partnership that is not owned or managed by ETE or ETP, none of the costs related to such awards are paid by ETE or ETP unless this partnership defaults under its obligations pursuant to these unit awards. We are recognizing non-cash compensation expense over the vesting period based on the grant date fair value of the ETE units awarded the ETP employees assuming no forfeitures.

Messrs. McCrea and Salinas vested in rights related to ETE units of 42,000 and 48,000, respectively, during 2012. Messrs. McCrea and Salinas had unvested rights related to ETE units of 42,000 and 48,000, respectively, as of December 31, 2012. The time restrictions related to these remaining unvested rights will lapse in 2013.

Qualified Retirement Plan Benefits. We have established a defined contribution 401(k) plan, which covers substantially all of our employees, including our named executive officers. Employees may elect to defer up to 100% of their eligible compensation after applicable taxes, as limited under the Internal Revenue Code. We make a matching contribution that is not less than the aggregate amount of matching contributions that would be credited to a participant's account based on a rate of match equal to 100% of each participant's elective deferrals up to 5% of covered compensation. The entire amount credited to the participant's account is fully vested and non-forfeitable at all times. We provide this benefit as a means to incentivize employees and provide them with an opportunity to save for their retirement.

Health and Welfare Benefits. All full-time employees, including our named executive officers, may participate in our health and welfare benefit programs including medical, dental, vision, flexible spending, life insurance and disability insurance.

Termination Benefits. Our named executive officers do not have any employment agreements that call for payments of termination or severance benefits or that provide for any payments in the event of a change in control of our General Partner. Our 2004 Unit Plan provides for immediate vesting of all unvested unit awards in the event of a change in control, as defined in the plan. In addition, our 2008 Incentive Plan provides the Compensation Committee with the discretion to provide for immediate vesting of

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all unvested unit awards in the event of a change of control, as defined in the plan. Please refer to "— Compensation Tables— Potential Payments upon a Terminated or Change of Control" for additional information.

Deferred Compensation Plan. We maintain a deferred compensation plan ("DC Plan"), which permits eligible highly compensated employees to defer a portion of their salary and/or bonus until retirement or termination of employment or other designated distribution. Under the DC Plan, each year eligible employees are permitted to make an irrevocable election to defer up to 50% of their annual base salary, 50% of their quarterly non-vested unit distribution income, and/or 50% of their discretionary performance bonus compensation to be earned for services performed during the following year. Pursuant to the DC Plan, ETP may make annual discretionary matching contributions to participants' accounts; however, we have not made any discretionary contributions to participants' accounts and currently have no plans to make any discretionary contributions to participants' accounts. All amounts credited under the DC Plan (other than discretionary credits) are immediately 100% vested. Participant accounts are credited with deemed earnings (or losses) based on hypothetical investment fund choices made by the participants among available funds.

Participants may elect to have their accounts distributed in one lump sum payment or in annual installments over a period of 3 or 5 years upon retirement, and in a lump sum upon other termination. Upon a change in control (as defined in the DC Plan) of ETP, all DC Plan accounts are immediately vested in full. However, distributions are not accelerated and, instead, are made in accordance with the DC Plan's normal distribution provisions unless a participant has elected to receive a change of control distribution pursuant to his deferral agreement.

Risk Assessment Related to our Compensation Structure. We believe our compensation plans and programs for our named executive officers, as well as our other employees, are appropriately structured and are not reasonably likely to result in material risk to the Partnership. We believe our compensation plans and programs are structured in a manner that does not promote excessive risk-taking that could harm our value or reward poor judgment. We also believe we have allocated our compensation among base salary and short and long-term compensation in such a way as to not encourage excessive risk-taking. In particular, we generally do not adjust base annual salaries for the executive officers and other employees significantly from year to year, and therefore the annual base salary of our employees is not generally impacted by our overall financial performance or the financial performance of an operating segment. We generally determine whether, and to what extent, our named executive officers receive a cash bonus based on our achievement of specified financial performance objectives as well as the individual contributions of our named executive officers to the Partnership's success. We use restricted units rather than unit options for equity awards because restricted units retain value even in a depressed market so that employees are less likely to take unreasonable risks to get, or keep, options "in-the-money." Finally, the time-based vesting over five years for our long-term incentive awards ensures that our employees' interests align with those of our Unitholders for the long-term performance of the Partnership.

Tax and Accounting Implications of Equity-Based Compensation Arrangements

Deductibility of Executive Compensation

We are a limited partnership and not a corporation for U.S. federal income tax purposes. Therefore, we believe that the compensation paid to the named executive officers is not subject to the deduction limitations under Section 162(m) of the Internal Revenue Code and therefore is generally fully deductible for federal income tax purposes.

Accounting for Unit-Based Compensation

For our unit-based compensation arrangements, including equity-based awards issued to certain of our named executive officers by an affiliate (as discussed above), we record compensation expense over the vesting period of the awards, as discussed further in Note 7 to our consolidated financial statements.

Compensation Committee Interlocks and Insider Participation

Messrs. Grimm and Byrne served on the Compensation Committee during 2012. During 2012, none of the members of the committee was an officer or employee of us or any of our subsidiaries or served as an officer of any company with respect to which any of our executive officers served on such company's board of directors. In addition, neither Mr. Grimm nor Mr. Byrne are former employees of ours or any of our subsidiaries.

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Report of Compensation Committee

The Compensation Committee of the board of directors of our General Partner has reviewed and discussed the section entitled "Compensation Discussion and Analysis" with the management of ETP. Based on this review and discussion, we have recommended to the board of directors of our General Partner that the Compensation Discussion and Analysis be included in this annual report on Form 10-K.

The Compensation Committee of the
Board of Directors of Energy Transfer Partners, L.L.C., the
general partner of the Energy Transfer Partners GP, L.P., the
general partner of Energy Transfer Partners, L.P.
Michael K. Grimm
Bill W. Byrne

The foregoing report shall not be deemed to be incorporated by reference by any general statement or reference to this annual report on Form 10-K into any filing under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, as amended, except to the extent that we specifically incorporate this information by reference, and shall not otherwise be deemed filed under those Acts.

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Compensation Tables

Summary Compensation Table

Name and Principal Position	Year	Salary ($)	Bonus ($) (1)	Equity Awards ($) (2)	Option Awards ($)	Non-Equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($) (3)	Total ($)
Kelcy L. Warren (4)	2012	$ 3,938	$ —	$ —	$ —	$ —	$ —	$ —	$ 3,938
Chief Executive	2011	3,240	—	—	—	—	—	—	3,240
Officer	2010	2,766	—	—	—	—	—	—	2,766
Martin Salinas, Jr.	2012	425,000	375,000	755,515	—	—	23,261	26,140	1,604,916
Chief Financial	2011	360,532	400,000	1,128,500	—	—	(6,462)	25,020	1,907,590
Officer	2010	356,058	480,000	999,600	—	—	7,648	27,250	1,870,556
Marshall S. (Mackie) McCrea, III	2012	750,000	700,000	1,510,985	—	—	—	12,802	2,973,787
President and Chief	2011	615,049	750,000	9,542,520	—	—	—	12,972	10,920,541
Operating Officer	2010	538,077	729,500	13,455,000	—	—	—	12,250	14,734,827
Thomas P. Mason	2012	500,000	500,000	1,359,900	—	—	—	35,998	2,395,898
Senior Vice	2011	432,901	750,000	1,805,600	—	—	—	32,590	3,021,091
President, General Counsel and Secretary	2010	427,513	482,530	999,600	—	—	—	34,990	1,944,633
Richard Cargile President of Midstream Operations	2012	237,500	230,000	1,379,880	—	—	3,534	12,279	1,863,193

(1) The discretionary cash bonus amounts for our named executive officers for 2012 reflect cash bonuses approved by the Compensation Committee in February 2013 that are expected to be paid in March 2013.

(2) Equity award amounts reflect the aggregate grant date fair value of unit awards granted for the periods presented, computed in accordance with FASB ASC Topic 718. See Note 7 to our consolidated financial statements for additional assumptions underlying the value of the equity awards.

(3) The amounts reflected for 2012 in this column include (i) contributions to the 401(k) plan made by ETP on behalf of the named executive officers of $10,067 and $11,875 for Mr. Salinas and Mr. Cargile, respectively, and $12,250 each for Messrs. McCrea and Mason, (ii) expenses paid by us for housing for Messrs. Salinas and Mason near our executive office in Dallas and (iii) the dollar value of life insurance premiums paid for the benefit of the named executive officers. Vesting in 401(k) contributions occurs immediately.

(4) Mr. Warren voluntarily determined that his salary would be reduced to $1.00 per year (plus an amount sufficient to cover his allocated payroll deductions for health and welfare benefits). He does not accept a cash bonus or any equity awards under the equity incentive plans.

Grants of Plan-Based Awards Table

Name	Grant Date	All Other Unit Awards: Number of Units (#)	All Other Option Awards: Number of Securities Underlying Options	Exercise or Base Price of Option Awards ($ / Unit)	Grant Date Fair Value of Unit Awards (1)

			(#)		
Kelcy L. Warren	N/A	—	—	—	$—
Martin Salinas, Jr.	1/10/2013	16,667	—	—	755,515
Marshall S. (Mackie) McCrea, III	1/10/2013	33,333	—	—	1,510,985
Thomas P. Mason	1/10/2013	30,000	—	—	1,359,900
Richard Cargile	1/10/2013	12,000	—	—	543,960
	3/14/2012	18,000	—	—	835,920

(1) We have computed the grant date fair value of unit awards in accordance with FASB ASC Topic 718, as further described above and in Note 7 to our consolidated financial statements.

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We do not have any non-equity incentive plans.

Narrative Disclosure to Summary Compensation Table and Grants of the Plan-Based Awards Table

A description of material factors necessary to understand the information disclosed in the tables above with respect to salaries, bonuses, equity awards, nonqualified deferred compensation earnings, and 401(k) plan contributions can be found in the compensation discussion and analysis that precedes these tables.

Outstanding Equity Awards at Year-End Table

		Unit Awards	
Name	Grant Date (1)	Equity Incentive Plan Awards: Number of Units That Have Not Vested (#) (1)	Equity Incentive Plan Awards: Market or Payout Value of Units That Have Not Vested ($) (2)
Kelcy L. Warren	N/A	—	$—
Martin Salinas, Jr.	1/10/2013	16,667	715,514
	12/20/2011	20,000	858,600
	12/15/2010	12,000	515,160
	12/15/2009	7,674	329,445
	12/22/2008	4,000	171,720
Marshall S. (Mackie) McCrea, III	1/10/2013	33,333	1,430,986
	12/20/2011	40,000	1,717,200
	5/2/2011	81,600	3,503,088
	1/14/2011	150,000	6,439,500
	12/15/2009	8,000	343,440
	12/22/2008	4,000	171,720
Thomas P. Mason	1/10/2013	30,000	1,287,900
	12/20/2011	32,000	1,373,760
	12/15/2010	12,000	515,160
	12/15/2009	7,274	312,273
	12/22/2008	4,000	171,720
	10/17/2008	10,000	429,300
Richard Cargile	1/10/2013	12,000	515,160
	3/14/2012	14,400	618,192

(1) Unit awards outstanding to Messrs. Salinas, McCrea, Mason and Cargile vest as follows:

- At a rate of 60% in December 2015 and 40% in December 2017 for awards granted in January 2013;
- Ratably in December of each year through 2016 for awards granted in December 2011 and March 2012;
- Ratably in December of each year through 2015 for awards granted in December 2010, January 2011 and May 2011;
- Ratably in December of each year through 2014 for awards granted in December 2009;
- In December 2013 for awards granted in December 2008; and
- In October 2013 for awards granted in October 2008.

(2) Market value was computed as the number of unvested awards as of December 31, 2012 multiplied by the closing price of our Common Units on December 31, 2012.

The amounts above do not include the equity awards granted to certain named executive officers in equity of ETE held by a partnership controlled by Mr. McReynolds. These awards are not issued pursuant to our equity incentive plans, and such awards are in the sole discretion of Mr. McReynolds.

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Option Exercises and Units Vested Table

Name	Unit Awards Number of Units Acquired on Vesting (#) (1)	Value Realized on Vesting ($) (1)
Kelcy L. Warren	—	$—
Martin Salinas, Jr.	18,038	780,107
Marshall S. (Mackie) McCrea, III	99,600	4,307,501
Thomas P. Mason	33,238	1,433,267
Richard Cargile	3,600	155,693

(1) Amounts presented represent the number of unit awards vested during 2012 and the value realized upon vesting of these awards, which is calculated as the number of units vested multiplied by the closing price of our Common Units upon the vesting date.

We have not issued option awards.

Nonqualified Deferred Compensation

Name	Executive Contributions in Last FY ($)	Registrant Contributions in Last FY ($)	Aggregate Earnings in Last FY ($)	Aggregate Withdrawals/ Distributions ($)	Aggregate Balance at Last FYE ($)
Kelcy L. Warren	$—	$—	$—	$—	$—
Martin Salinas, Jr.	25,926	—	23,261	—	202,849
Marshall S. (Mackie) McCrea, III	—	—	—	—	—
Thomas P. Mason	—	—	—	—	—
Richard Cargile	97,338	—	3,534	—	100,872

The aggregate earnings reflected above for Mr. Salinas and Mr. Cargile are included in total compensation in the "Summary Compensation Table."

A description of the key provisions of the Partnership's deferred compensation plan can be found in the compensation discussion and analysis above.

Potential Payments upon a Termination or Change of Control

Equity Awards. As discussed in our Compensation Discussion and Analysis above, any unvested equity awards granted pursuant to the 2004 Unit Plan will automatically become vested upon a change of control. Assuming that a change of control occurred on December 31, 2012, the fair value of the unvested awards granted pursuant to the 2004 Unit Plan as of December 31, 2012 were $171,720 for Mr. Salinas, $171,720 for Mr. McCrea and $1,116,180 for Mr. Mason, respectively. In addition, Messrs. Salinas and McCrea hold unvested rights to receive ETE units granted by McReynolds Energy Partners, L.P. that would become immediately vested in connection with a change in control. Assuming that a change of control occurred on December 31, 2012, the fair value of these awards would have been $2,183,040 for Mr. Salinas and $1,910,160 for Mr. McCrea. Although any unvested equity awards granted under the 2008 Incentive Plan may also become vested upon a change of control at the discretion of the Compensation Committee, this discussion assumes a scenario in which the Compensation Committee does not exercise such discretion.

While any individual award agreement may contain a modified definition, a change in control is generally defined under the 2004 Unit Plan as the occurrence of any of the following events: (i) ETP GP ceases to be our general partner; (ii) ETE ceases to own, directly or indirectly through wholly-owned subsidiaries, in the aggregate at least 51% of the capital stock or equity interests of ETP GP; (iii) the sale of all or substantially all of ETP's assets (other than to any affiliate of ETE); or (iv) a liquidation or dissolution of ETP. For purposes of the rights with respect to ETE units granted by McReynolds Energy Partners, L.P., a change in control means a "change in control" as defined in the 2004 Unit Plan, but a change in control will also be considered to have occurred if any single party, other than Kelcy

Warren, acquires either: (a) more than 90% of the then-outstanding limited partner units of ETE; or (b) more than 51% of the ownership of LE GP, LLC. Under the 2008 Incentive Plan, a “change of control” is generally defined as the occurrence of one or more of the following events: (1) any person or group becomes the beneficial owner of 50% or more of our voting power or voting securities; (2) the complete liquidation of either ETP LLC, ETP GP, or us; (3) the sale of all or substantially all of ETP GP's or our assets to anyone other than us, ETP GP or one of our affiliates; or (4) a person other than ETP LLC, ETP GP or one of their affiliates becomes our general partner.

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Deferred Compensation Plan. As discussed in our Compensation Discussion and Analysis above, all amounts under the DC Plan (other than discretionary credits) are immediately 100% vested. Upon a change in control (as defined in the DC Plan), distributions from the DC Plan would be made in accordance with the DC Plan's normal distribution provisions. A change in control is generally defined in the DC Plan as any change in control event within the meaning of Treasury Regulation Section 1.409A-3(i)(5).

Director Compensation Table

The Compensation Committee periodically reviews and makes recommendations regarding the compensation of the directors of our General Partner. In 2012, non-employee directors of our General Partner received an annual fee of $40,000 plus $1,200 for each committee meeting attended. Beginning in 2013, non-employee directors will receive an annual fee of $50,000 in cash. Additionally, the Chairman of the Audit Committee receives an annual fee of $15,000 and the members of the Audit Committee receive an annual fee of $10,000. The Chairman of the Compensation Committee receives an annual fee of $7,500 and the members of the Compensation Committee receive an annual fee of $5,000. In connection with the Citrus Acquisition, Holdco Transaction and Sunoco Acquisition, the Board of Directors appointed Messrs. Byrne, Glaske and Grimm to serve on the Conflicts Committee to address potential conflicts of interest in the transactions. For their service on the Conflicts Committee, which met 27 times during 2012, Messrs. Byrne, Glaske and Grimm received additional compensation of $2,500 per Conflicts Committee meeting. Beginning in 2013, members of the Conflicts Committee will receive cash payments on a to-be-determined basis for each Conflicts Committee assignment. Employee directors, including Messrs. Warren and McCrea, do not receive any fees for service as directors. In addition, the non-employee directors participate in our 2004 Unit Plan and 2008 Incentive Plan. Each director who is not also (i) a shareholder or a direct or indirect employee of any parent, or (ii) a direct or indirect employee of ETP LLC, ETP, or a subsidiary, who is elected or appointed to the Board for the first time shall automatically receive, on the date of his or her election or appointment, an award of 2,500 unvested ETP Common Units. For 2012, under our 2004 Unit Plan and 2008 Incentive Plan, the non-employee directors of our General Partner each received annual grants of restricted ETP Common Units equal to an aggregate of $50,000 divided by the closing price of our Common Units on the date of grant. These ETP Common Units vest over three years at one-third per year. Beginning in 2013, non-employee directors receive annual grants of restricted ETP Common Units equal to an aggregate of $100,000 divided by the closing price of our Common Units on the date of grant. These ETP Common Units will vest 60% after the third year and 40% after the fifth year after the grant date. The compensation paid to the non-employee directors of our General Partner in 2012 is reflected in the following table:

Name	Fees Paid in Cash ($) (1)	Unit Awards ($) (2)	All Other Compensation ($)	Total ($)
Bill W. Byrne	$140,700	$40,847	$ —	$181,547
Paul E. Glaske	140,700	40,847	—	181,547
Ted Collins, Jr.	40,000	40,847	—	80,847
Michael K. Grimm	142,000	40,847	—	182,847

(1) Fees paid in cash are based on amounts paid during the period.

(2) Unit award amounts reflect the aggregate grant date fair value of awards granted based on the market price of Common Units as of the grant date, reduced by the present value of the expected distributions during the vesting period.

As of December 31, 2012, Messrs. Byrne, Glaske, Collins and Grimm each had 1,954 unit awards outstanding.

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ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED UNITHOLDER MATTERS

Equity Compensation Plan Information

The following table sets forth, in tabular format, a summary of certain information related to our equity incentive plans as of December 31, 2012:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	1,859,159	$—	2,815,982
Equity compensation plans not approved by security holders	—	—	—
Total	1,859,159	$—	2,815,982

Energy Transfer Partners, L.P. Units

The following table sets forth certain information as of February 2, 2013, regarding the beneficial ownership of our securities by certain beneficial owners, each director and named executive officer of our General Partner and all directors and executive officers of our General Partner as a group. The General Partner knows of no other person not disclosed herein who beneficially owns more than 5% of our Common Units.

Title of Class	Name and Address of Beneficial Owner (1)	Beneficially Owned (2) (3)	Percent of Class	
Common Units	Kelcy L. Warren	21,107	*	
	Marshall S. (Mackie) McCrea , III	151,313	*	
	Martin Salinas, Jr.	40,185	*	
	Thomas P. Mason	70,121	*	
	Richard Cargile	4,362	*	
	Bill W. Byrne	97,568	*	
	Paul E. Glaske	97,495	*	
	Michael K. Grimm	21,762	*	
	Ted Collins, Jr.	98,656	*	
	All Directors and Executive Officers as a Group (9 Persons)	602,569	*	
	ETE (4)	50,226,967	16.7	%
Class E Units	Heritage Holdings, Inc. (5)	8,853,832	100	%
Class F Units	Sunoco, Inc. (6)	90,706,000	100	%

*Less than 1%

(1) The address for Messrs. Warren, Salinas, Mason, Cargile, Byrne, Glaske, Grimm and Collins 3738 Oak Lawn Avenue, Dallas, Texas 75219. The address for Heritage Holdings is 8801 S. Yale Avenue, Suite 310, Tulsa, Oklahoma 74137. The address for Mr. McCrea is 800 E. Sonterra Blvd., San Antonio, Texas 78258. The address for ETE is 3738 Oak Lawn Avenue, Dallas, Texas 75219. The address for Sunoco, Inc. is 1818 Market Street, Suite 1500, Philadelphia, PA 19103.

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

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(3) Due to the ownership by certain officers and directors of the general partner of ETE of equity interests in ETE (either directly or through one or more entities) and due to their positions as directors of the general partner of ETE, they may be deemed to beneficially own the limited partnership interests held by ETE, to the extent of their respective interests therein. Any such deemed ownership is not reflected in the table.

(4) ETE owns all member interests of Energy Transfer Partners, L.L.C and all of the Class A limited partner interests and Class B limited partner interests in Energy Transfer Partners GP, L.P. Energy Transfer Partners, L.L.C. is the general partner of Energy Transfer Partners GP, L.P. with a .01% general partner interest. LE GP, LLC, the general partner of ETE, may be deemed to beneficially own the Common Units owned of record by ETE. The members of LE GP, LLC are Ray C. Davis and Kelcy L. Warren.

(5) The Partnership indirectly owns 100% of the common stock of Heritage Holdings, Inc.

(6) The Partnership indirectly owns 100% of the common stock of Sunoco, Inc.

In connection with the Parent Company Credit Agreement, ETE and certain of its subsidiaries entered into a Pledge and Security Agreement (the “Security Agreement”) with Credit Suisse AG, Cayman Islands Branch, as collateral agent (the “Collateral Agent”). The Security Agreement secures all of ETE’s obligations under the Parent Company Credit Agreement and grants to the Collateral Agent a continuing first priority lien on, and security interest in, all of ETE’s and the other grantors’ tangible and intangible assets.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

As a policy matter, the Conflicts Committee generally reviews any proposed related-party transaction that may be material to the Partnership to determine whether the transaction is fair and reasonable to the Partnership. The Partnership's board of directors makes the determinations as to whether there exists a related-party transaction in the normal course of reviewing transactions for approval as the Partnership's board of directors is advised by its management of the parties involved in each material transaction as to which the board of directors' approval is sought by the Partnership's management. In addition, the Partnership's board of directors makes inquiries to independently ascertain whether related parties may have an interest in the proposed transaction. While there are no written policies or procedures for the board of directors to follow in making these determinations, the Partnership's board makes those determinations in light of its fiduciary duties to the Unitholders. The Partnership Agreement provides that any matter approved by the Conflicts Committee will be conclusively deemed to be fair and reasonable to the Partnership, approved by all the partners of the Partnership and not a breach by the General Partner or its Board of Directors of any duties they may owe the Partnership or the Unitholders.

ETE owns directly and indirectly the general partner interest in ETP GP, 100% of the ETP Incentive Distribution Rights and 50,226,967 ETP Common Units.

We have a shared services agreement in which we provide various general and administrative services for ETE. See discussion in Note 13 to our consolidated financial statements.

We have an operating lease agreement with the former owners of Energy Transfer Group, L.L.C. ("ETG"), which we acquired in 2009. These former owners include Mr. Warren and Mr. Ray C. Davis, a former ETP board member. We pay these former owners $5 million in operating lease payments per year through 2017. With respect to the related party transaction with ETG, the Conflicts Committee of ETP met numerous times prior to the consummation of the transaction to discuss the terms of the transaction. The committee made the determination that the sale of ETG to ETP was fair and reasonable to ETP and that the terms of the operating lease between ETP and the former owners of ETG are fair and reasonable to ETP.

We received $18 million, $17 million and $6 million in management fees from ETE for the provision of various general and administrative services for ETE’s benefit for the years ended December 31, 2012, 2011 and 2010, respectively. The increase recorded in the years ended December 31, 2012 and 2011 were the result of increased service fees related to the provision of various general and administrative services for Regency which was acquired by ETE in 2010.

Immediately following the closing of the Partnership's acquisition of Sunoco, ETE contributed its interest in Southern Union into Holdco, an ETP-controlled entity, in exchange for a 60% equity interest in Holdco. In conjunction with ETE's contribution, the Partnership contributed its interest in Sunoco to Holdco and retained a 40% equity interest in

Holdco. Prior to the contribution of Sunoco to Holdco, Sunoco contributed $2.0 billion of cash and its interests in Sunoco Logistics to the Partnership in exchange for 90,706,000 Class F Units representing limited partner interests in the Partnership. The Class F Units are entitled to 35% of the quarterly cash distribution generated by the Partnership and its subsidiaries other than Holdco, subject to a maximum cash distribution of $3.75 per Class F Unit per year, which is the current level.

On February 27, 2013, Southern Union entered into a definitive contribution agreement to contribute to Regency all of the issued and outstanding membership interest in Southern Union Gathering Company, LLC, and its subsidiaries, including SUGS. The

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consideration to be paid by Regency in connection with this transaction will consist of (i) the issuance of 31,372,419 Regency common units to Southern Union, (ii) the issuance of 6,274,483 Regency Class F units to Southern Union, (iii) the distribution of $570 million in cash to Southern Union, and (iv) the payment of $30 million in cash to a subsidiary of ETP. The Regency Class F units will have the same rights, terms and conditions as the Regency common units, except that Southern Union will not receive distributions on the Regency Class F units for the first eight consecutive quarters following the closing, and the Regency Class F units will thereafter automatically convert into Regency common units on a one-for-one basis. Upon the closing of the transaction, ETE will agree to forego all distributions with respect to its IDRs on the Regency common units issued in the transaction for the first eight consecutive quarters following the closing. The transaction is expected to close in the second quarter of 2013.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The following sets forth fees billed by Grant Thornton LLP for the audit of our annual financial statements and other services rendered:

	Years Ended December 31,	
	2012	2011
Audit fees[(1)]	$4,348,000	$1,966,500
Audit related fees[(2)]	25,000	372,000
Tax fees[(3)]	1,525	9,553
Total	$4,374,525	$2,348,053

(1) Includes fees for audits of annual financial statements of our companies, reviews of the related quarterly financial statements, and services that are normally provided by the independent accountants in connection with statutory and regulatory filings or engagements, including reviews of documents filed with the SEC and services related to the audit of our internal control over financial reporting.

(2) Includes fees in 2012 in connection with the service organization control report on Southern Union's centralized data center. Includes fees in 2011 for attestation engagements of subsidiary entities in connection with the contribution of the Partnership's retail propane operations to AmeriGas Partners, L.P. in January 2012.

(3) Includes fees related to state and local tax consultation and training.

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

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

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

- the auditors' internal quality-control procedures;
- any material issues raised by the most recent internal quality-control review, or peer review, of the external auditors;
- the independence of the external auditors;
- the aggregate fees billed by our external auditors for each of the previous two years; and
- the rotation of the lead partner.

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PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed as a part of this Report:
(1) Financial Statements - see Index to Financial Statements appearing on page F-1.
(2) Financial Statement Schedules - None.
(3) Exhibits - see Index to Exhibits set forth on page E-1.

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SIGNATURES

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

ENERGY TRANSFER PARTNERS, L.P.

By Energy Transfer Partners GP, L.P,
its general partner.

By Energy Transfer Partners, L.L.C.,
its general partner

By: /s/ Kelcy L. Warren
Kelcy L. Warren
Chief Executive Officer and officer duly authorized to sign on behalf of the registrant

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

Signature	Title	Date
/s/ Kelcy L. Warren Kelcy L. Warren	Chief Executive Officer and Chairman of the Board (Principal Executive Officer)	March 1, 2013
/s/ Martin Salinas, Jr. Martin Salinas, Jr.	Chief Financial Officer (Principal Financial and Accounting Officer)	March 1, 2013
/s/ Bill W. Byrne Bill W. Byrne	Director	March 1, 2013
/s/ Marshall S. McCrea, III Marshall S. McCrea, III	President, Chief Operating Officer and Director	March 1, 2013
/s/ Paul E. Glaske Paul E. Glaske	Director	March 1, 2013
/s/ Ted Collins, Jr. Ted Collins, Jr.	Director	March 1, 2013
/s/ Michael K. Grimm Michael K. Grimm	Director	March 1, 2013

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INDEX TO EXHIBITS

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

	Exhibit Number	Description
(4)	2.1	Redemption and Exchange Agreement dated as of May 10, 2010 by and between Energy Transfer Equity, L.P. and Energy Transfer Partners, L.P.
(31)	2.2	Purchase Agreement, dated March 22, 2011, among ETP-Regency Midstream Holdings, LLC, LDH Energy Asset Holdings LLC and Louis Dreyfus Highbridge Energy LLC, Energy Transfer Partners, L.P. and Regency Energy Partners LP.
(41)	2.3	Contribution and Redemption Agreement by and among Energy Transfer Partners, L.P., Energy Transfer Partners GP, L.P., Heritage ETC, L.P. and AmeriGas Partners, L.P. dated October 15, 2011.
(42)	2.4	Amendment No. 1, dated December 1, 2011, to the Contribution and Redemption Agreement by and among Energy Transfer Partners, L.P., Energy Transfer Partners GP, L.P., Heritage ETC, L.P. and AmeriGas Partners, L.P. dated October 15, 2011.
(47)	2.5	Amendment No. 2, dated January 11, 2012, to the Contribution and Redemption Agreement by and among Energy Transfer Partners, L.P., Energy Transfer Partners GP, L.P., Heritage ETC, L.P. and AmeriGas Partners, L.P. dated October 15, 2011.
(48)	2.6	Amendment No. 2, dated as of March 23, 2012, to the Amended and Restated Agreement and Plan of Merger, by and among Energy Transfer Partners, L.P., Citrus ETP Acquisition L.L.C., Energy Transfer Equity, L.P., Southern Union Company, and CrossCountry Energy, LLC dated July 19, 2011.
(38)	2.7	Amendment No. 1, dated as of September 14, 2011, to the Amended and Restated Agreement and Plan of Merger, dated as of July19, 2011, by and between Energy Transfer Partners, L.P. and Energy Transfer Equity, L.P.
(43)	2.8	Amended and Restated Agreement and Plan of Merger, dated as of July 19, 2011, by and between Energy Transfer Partners, L.P. and Energy Transfer Equity, L.P.
(49)	2.9	Agreement and Plan of Merger, dated as of April 29, 2012 by and among Energy Transfer Partners, L.P., Sam Acquisition Corporation, Energy Transfer Partners GP, L.P., Sunoco, Inc. and, for certain limited purposes set forth therein, Energy Transfer Equity, L.P.
(50)	2.10	Amendment No. 1, dated as of June 15, 2012, to the Agreement and Plan of Merger, dated as of April 29, 2012, by and among Energy Transfer Partners, L.P., Sam Acquisition Corporation, Energy Transfer Partners GP, L.P., Sunoco, Inc., and, for certain limited purposes set forth therein, Energy Transfer Equity, L.P.
(51)	2.11	Transaction Agreement, dated as of June 15, 2012, by and among Energy Transfer Partners, L.P., Energy Transfer Partners GP, L.P., Heritage Holdings, Inc., Energy Transfer Equity, L.P., ETE Sigma Holdco, LLC and ETE Holdco Corporation.
(3)	3.1	Second Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.) dated as of July 28, 2009.
(52)	3.1.1	Amendment No. 1, dated March 26, 2012, to the Second Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P., dated July 28, 2009.
(53)	3.1.2	Amendment No. 2 to Second Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P., dated October 5, 2012.
(1)	3.2	Amended and Restated Agreement of Limited Partnership of Heritage Operating, L.P.
(2)	3.2.1	

		Amendment No. 1 to Amended and Restated Agreement of Limited Partnership of Heritage Operating, L.P.
(6)	3.2.2	Amendment No. 2 to Amended and Restated Agreement of Limited Partnership of Heritage Operating, L.P.
(7)	3.2.3	Amendment No. 3 to Amended and Restated Agreement of Limited Partnership of Heritage Operating, L.P.
(7)	3.3	Amended Certificate of Limited Partnership of Energy Transfer Partners, L.P.
(5)	3.4	Amended Certificate of Limited Partnership of Heritage Operating, L.P.

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	Exhibit Number	Description
(23)	3.5	Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners GP, L.P.
(54)	3.5.1	Amendment No. 2, dated March 26, 2012, to the Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners GP, L.P., dated as of April 17, 2007.
(25)	3.6	Fourth Amended and Restated Limited Liability Company Agreement of Energy Transfer Partners, L.L.C.
(55)	3.6.1	Amendment No. 1, dated March 26, 2012, to the Fourth Amended and Restated Limited Liability Company Agreement of Energy Transfer Partners, L.L.C., dated as of August 10, 2010.
(27)	3.13	Certificate of Formation of Energy Transfer Partners, L.L.C.
(27)	3.13.1	Certificate of Amendment of Energy Transfer Partners, L.L.C.
(27)	3.14	Restated Certificate of Limited Partnership of Energy Transfer Partners GP, L.P.
(8)	4.3	Indenture dated January 18, 2005 among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee.
(9)	4.4	First Supplemental Indenture dated January 18, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee.
(14)	4.5	Second Supplemental Indenture dated as of February 24, 2005 to Indenture dated as of January 18, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee.
(15)	4.11	Form of Senior Indenture of Energy Transfer Partners, L.P.
(15)	4.12	Form of Subordinated Indenture of Energy Transfer Partners, L.P.
(21)	4.13	Fourth Supplemental Indenture dated as of June 29, 2006 to Indenture dated January 18, 2005, among Energy Transfer Partners, L.P, the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee.
(16)	4.14	Fifth Supplemental Indenture dated as of October 23, 2006 to Indenture dated January 18, 2005, among Energy Transfer Partners, L.P, the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee.
(26)	4.15	Sixth Supplemental Indenture dated March 28, 2008, by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee.
(24)	4.16	Seventh Supplemental Indenture dated December 23, 2008, by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee.
(10)	4.16.1	Eighth Supplemental Indenture dated April 7, 2009, by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee.
(17)	4.17	Registration Rights Agreement, dated November 1, 2006, between Energy Transfer Partners, L.P. and Energy Transfer Equity, L.P.
(37)	4.18	Ninth Supplemental Indenture, dated as of May 12, 2011, to the Indenture dated January 18, 2005, by and between Energy Transfer Partners, L.P. and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee.
(44)	4.19	Tenth Supplemental Indenture, dated as of January 17, 2012, to the Indenture dated January 18, 2005, by and between Energy Transfer Partners, L.P. and U.S. Bank National Assocation (as successor to Wachovia Bank, National Association), as trustee.
(56)	4.20	Eleventh Supplemental Indenture dated as of January 22, 2013 by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee.

(57)	4.21	Indenture, dated as of March 31 2009, between Sunoco, Inc. and U.S. Bank National Association, as trustee.
(58)	4.22	First Supplemental Indenture, dated as of March 31, 2009, between Sunoco, Inc. and U.S. Bank National Association, as trustee, to the Indenture, dated as of March 31, 2009, relating to Sunoco's 9.625% Senior Notes due 2015.
(59)	4.23	Second Supplemental Indenture, dated as of October 5, 2012, among Energy Transfer Partners, L.P., Sunoco, Inc. and U.S. Bank National Association, as trustee, to Indenture, dated as of March 31, 2009.

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	Exhibit Number	Description
(60)	4.24	Indenture, dated as of June 30, 2000, between Sunoco, Inc. and U.S. Bank National Association, as successor trustee to Citibank, N.A.
(61)	4.25	First Supplemental Indenture, dated as of October 5, 2012, among Energy Transfer Partners, L.P., Sunoco, Inc. and U.S. Bank National Association, as successor trustee to Citibank, N.A., to the Indenture, dated as of June 30, 2000.
(62)	4.26	Indenture, dated as of May 15, 1994, between Sunoco, Inc. and U.S. Bank National Association, as successor trustee to Citibank, N.A., relating to Sunoco, Inc.'s 9.00% Debentures due 2024.
(63)	4.27	First Supplemental Indenture, dated as of October 5, 2012, among Energy Transfer Partners, L.P., Sunoco, Inc. and U.S. Bank National Association, as successor trustee to Citibank, N.A., to the Indenture, dated as of May 15, 1994.
(29)	10.1	Amended and Restated Credit Agreement, dated July 20, 2007, among Energy Transfer Partners, L.P., the borrower, and Wachovia Bank, National Association, as administrative agent, LC issuer and swingline lender, Bank of America, N.A., as syndication agent, BNP Paribas, JPMorgan Chase Bank, N.A. and the Royal Bank of Scotland PLC, as co-documentation agents, and Citibank, N.A., Credit Suisse, Cayman Islands Branch, Deutsche Bank Securities, Inc., Morgan Stanley Bank, Suntrust Bank and UBS Securities, LLC, as senior managing agents, and other lenders party hereto.
(28)	+ 10.6.6	Energy Transfer Partners, L.P. Amended and Restated 2004 Unit Plan.
(22)	+ 10.6.8	Energy Transfer Partners, L.P. 2008 Long-Term Incentive Plan.
(30)	+ 10.6.9	Energy Transfer Partners Deferred Compensation Plan.
(45)	+ 10.6.10	Form of Grant Agreement under the Energy Transfer Partners, L.P. Amended and Restated 2004 Unit Plan and the 2008 Energy Transfer Partners, L.P. Long-Term Incentive Plan.
(46)	+ 10.6.11	Energy Transfer Partners, L.P. Midstream Bonus Plan.
(11)	10.42	Purchase and Sale Agreement, dated January 26, 2005, among HPL Storage, LP and AEP Energy Services Gas Holding Company II, L.L.C., as Sellers, and La Grange Acquisition, L.P., as Buyer.
(12)	10.43	Cushion Gas Litigation Agreement, dated January 26, 2005, by and among AEP Energy Services Gas Holding Company II, L.L.C. and HPL Storage LP, as Sellers, and La Grange Acquisition, L.P., as Buyer, and AEP Asset Holdings LP, AEP Leaseco LP, Houston Pipe Line Company, LP and HPL Resources Company LP, as Companies.
(18)	10.51	Purchase and Sale Agreement, dated as of September 14, 2006, among Energy Transfer Partners, L.P. and EFS-PA, LLC (a/k/a GE Energy Financial Services), CDPQ Investments (U.S.), Inc., Lake Bluff, Inc., Merrill Lynch Ventures, L.P. and Kings Road Holdings I, LLC.
(19)	10.52	Redemption Agreement, dated September 14, 2006, between Energy Transfer Partners, L.P. and CCE Holdings, LLC.
(20)	10.53	Letter Agreement, dated September 14, 2006, between Energy Transfer Partners, L.P. and Southern Union Company.
(21)	10.54	Fourth Amended and Restated Credit Agreement dated as of August 31, 2006 between and among Heritage Operating L.P., as the Borrower, and the Banks parties thereto, as lenders, and Bank of Oklahoma, National Association, as administrative agent and joint lead arranger for the Banks, JPMorgan Chase Bank, N.A., as syndication agent for the Banks, and J.P. Morgan Securities Inc., as joint lead arranger for the Banks.
(23)	10.55	Note Purchase Agreement, dated as of November 17, 2004, by and among Transwestern Pipeline Company, LLC and the Purchasers parties thereto.
(23)	10.55.1	Amendment No. 1 to the Note Purchase Agreement, dated as of April 18, 2007, by and among Transwestern Pipeline Company, LLC and the Purchasers parties thereto.

(23)	10.56	Note Purchase Agreement, dated as of May 24, 2007, by and among Transwestern Pipeline Company, LLC and the Purchasers parties thereto.
(13)	10.56.1	Note Purchase Agreement, dated December 9, 2009, by and among Transwestern Pipeline Company, LLC and the Purchasers parties thereto.
(32)	10.57	Guarantee, dated as of March 22, 2011, by Energy Transfer Partners, L.P. in favor of Louis Dreyfus Highbridge Energy LLC.
(33)	10.58	Assumption, Contribution and Indemnification Agreement, dated as of March 22, 2011, by and between Energy Transfer Partners, L.P. and Regency Energy Partners LP.
(34)	10.59	Amended and Restated Energy Transfer Partners, L.P. Midstream Bonus Plan dated April 18, 2011

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	Exhibit Number	Description
(35)	10.60	Amended and Restated Limited Liability Company Agreement of ETP-Regency Midstream Holdings, LLC, dated May 2, 2011.
(36)	10.61	Term Loan Agreement dated as of July 28, 2011, by and among Fayetteville Express Pipeline LLC, The Royal Bank of Scotland plc, as administrative agent, and certain other agents and lenders party thereto.
(39)	10.62	Amendment No. 1, dated as of September 14, 2011, to Second Amended and Restated Agreement and Plan of Merger, dated as of July 19, 2011, by and among Energy Transfer Equity, L.P., Sigma Acquisition Corporation and Southern Union Company.
(40)	10.63	Second Amended and Restated Credit Agreement dated as of October 27, 2011 among Energy Transfer Partners, L.P., Wells Fargo Bank, National Association, as Administrative Agent, Swingline Lender and an LC Issuer, the other lenders party thereto and Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated and RBS Securities Inc., as Joint Lead Arrangers and Joint Book Managers.
(64)	10.64	Guarantee of Collection made as of March 26, 2012, by Citrus ETP Finance LLC, to Energy Transfer Partners, L.P.
(65)	10.65	Support Agreement, dated March 26, 2012, by and among PEPL Holdings, LLC, Energy Transfer Partners, L.P., and Citrus ETP Finance LLC.
(66)	10.66	Capital Stock Agreement dated June 30, 1986, as amended April 3, 2000 ("Agreement"), among El Paso Energy Corporation (as successor in interest to Sonat, Inc.); CrossCountry Energy, LLC (assignee of Enron Corp., which is the successor in interest to InterNorth, Inc. by virtue of a name change and successor in interest to Houston Natural Gas Corporation by virtue of a merger) and Citrus Corp.
(67)	10.67	Certificate of Incorporation of Citrus Corp.
(68)	10.68	By-Laws of Citrus Corp.
(69)	10.69	Contingent Residual Support Agreement by and among Energy Transfer Partners, L.P., AmeriGas Finance LLC, AmeriGas Finance Corp., AmeriGas Partners, L.P. and, for certain limited purposes, UGI Corporation, dated January 12, 2012.
(70)	10.70	Unitholder Agreement by and among Energy Transfer Equity, L.P., Energy Transfer Partners, L.P., Energy Transfer Partners GP, L.P., Heritage ETC, L.P. and AmeriGas Partners, L.P. dated January 12, 2012.
(71)	10.71	Letter agreement by and among Energy Transfer Partners, L.P., Energy Transfer Partners GP, L.P., Heritage ETC, L.P. and AmeriGas Partners, L.P, dated January 11, 2012.
(72)	10.72	Letter Agreement, dated as of April 29, 2012, by and among Energy Transfer Partners, L.P. and Energy Transfer Equity, L.P.
(73)	10.73	Purchase and Sale Agreement dated as of December 14, 2012 among Southern Union Company, Plaza Missouri Acquisition, Inc. and for certain limited purposes The Laclede Group, Inc.
(74)	10.74	Purchase and Sale Agreement dated as of December 14, 2012 among Southern Union Company, Plaza Massachusetts Acquisition, Inc. and for certain limited purposes, The Laclede Group, Inc.
(*)	12.1	Computation of Ratio of Earnings to Fixed Charges.
(*)	21.1	List of Subsidiaries.
(*)	23.1	Consent of Grant Thornton LLP.
(*)	23.2	Consent of Ernst & Young LLP.
(*)	31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
(*)	31.2	

		Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
(**)	32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
(**)	32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
(**)	99.1	Report of Independent Registered Public Accounting Firm — Ernst & Young LLP opinion on consolidated financial statements of Sunoco Logistics Partners LP.
(**)	99.2	Report of Independent Registered Public Accounting Firm — Ernst & Young LLP opinion on internal controls over financial reporting of Sunoco Logistics Partners LP.
(75)	99.3	Statement of Policies Relating to Potential Conflicts among Energy Transfer Partners, L.P., Energy Transfer Equity, L.P. and Regency Energy Partners LP dated as of April 26, 2011.

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	Exhibit Number	Description
(*)	101	Interactive data files pursuant to Rule 405 of Regulation S-T: (i) our Consolidated Balance Sheets as of December 31, 2012 and December 31, 2011; (ii) our Consolidated Statements of Operations for the years ended December 31, 2012, 2011 and 2010; (iii) our Consolidated Statements of Comprehensive Income for the years ended December 31, 2012, 2011 and 2010; (iv) our Consolidated Statement of Partners' Capital for the years ended December 31, 2012, 2011 and 2010; (v) our Consolidated Statements of Cash Flows for the years ended December 31, 2012, 2011 and 2010; and (vi) the notes to our Consolidated Financial Statements.

* Filed herewith.
** Furnished herewith.
\+ Denotes a management contract or compensatory plan or arrangement.

(1) Incorporated by reference the same numbered Exhibit to the Registrant's Registration Statement on Form S-1/A, File No. 333-04018, filed with the Commission on June 21, 1996.
(2) Incorporated by reference to the same numbered Exhibit to the Registrant's Form 10-K for the year ended August 31, 2000.
(3) Incorporated by reference to the same numbered Exhibit to the Registrant's Form 8-K filed July 29, 2009.
(4) Incorporated by reference to the same numbered Exhibit to the Registrant's Form 8-K/A filed June 2, 2010.
(5) Incorporated by reference to the same numbered Exhibit to the Registrant's Form 10-Q for the quarter ended February 28, 2002.
(6) Incorporated by reference to the same numbered Exhibit to the Registrant's Form 10-Q for the quarter ended May 31, 2002.
(7) Incorporated by reference as the same numbered Exhibit to the Registrant's Form 10-Q for the quarter ended February 29, 2004.
(8) Incorporated by reference to Exhibit 4.1 to the Registrant's Form 8-K filed January 19, 2005.
(9) Incorporated by reference to Exhibit 4.2 of the Registrant's Form 8-K filed on January 19, 2005.
(10) Incorporated by reference to Exhibit 4.2 of the Registrant's Form 8-K filed on April 7, 2009.
(11) Incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed February 1, 2005.
(12) Incorporated by reference to Exhibit 10.2 to the Registrant's Form 8-K filed February 1, 2005.
(13) Incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed December 14, 2009.
(14) Incorporated by reference to Exhibit 10.45 to the Registrant's Form 10-Q for the quarter ended February 28, 2005.
(15) Incorporated by reference to the same numbered Exhibit to the Registrant's Form S-3 filed August 9, 2006.
(16) Incorporated by reference to Exhibit 4.1 to the Registrant's Form 8-K filed October 25, 2006.
(17) Incorporated by reference to Exhibit 3.1.10 to the Registrant's Form 8-K filed November 3, 2006.
(18) Incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed September 18, 2006.
(19) Incorporated by reference to Exhibit 10.2 to the Registrant's Form 8-K filed September 18, 2006.
(20) Incorporated by reference to Exhibit 10.3 to the Registrant's Form 8-K filed September 18, 2006.
(21) Incorporated by reference to the same numbered Exhibit the Registrant's Form 10-K for the year ended August 31, 2006.
(22) Incorporated by reference to Exhibit A to the Proxy Statement filed by the Registrant November 21, 2008.
(23) Incorporated by reference to the same numbered Exhibit to the Registrant's Form 10-Q for the quarter ended May 31, 2007.

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(24) Incorporated by reference to Exhibit 4.2 to the Registrant’s Form 8-K filed December 23, 2008.
(25) Incorporated by reference to Exhibit 3.1 to the Registrant’s Form 8-K filed August 10, 2010.
(26) Incorporated by reference to Exhibit 4.2 to the Registrant’s Form 8-K filed March 31, 2008.
(27) Incorporated by reference to the same numbered Exhibit to the Registrant’s Form 10-Q for the quarter ended March 31, 2010.
(28) Incorporated by reference to the same numbered Exhibit to the Registrant’s Form 10-Q for the quarter ended June 30, 2008.
(29) Incorporated by reference to the same numbered Exhibit to the Registrant’s Form 8-K filed July 23, 2007.
(30) Incorporated by reference to Exhibit 10.1 to the Registrant’s Form 10-Q for the quarter ended March 31, 2010.
(31) Incorporated by reference to Exhibit 2.1 to Registrant's Form 8-K/A filed on March 25, 2011.
(32) Incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K/A filed on March 25, 2011.
(33) Incorporated by reference to Exhibit 10.2 to the Registrant's Form 8-K/A filed on March 25, 2011.
(34) Incorporated by reference to Exhibit 10.5 to the Registrant's Form 10-Q filed on August 8, 2011.
(35) Incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed May 2, 2011.
(36) Incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed August 2, 2011.
(37) Incorporated by reference to Exhibit 4.2 to the Registrant's Form 8-K filed May 12, 2011.
(38) Incorporated by reference to Exhibit 2.1 to the Registrant's Form 8-K filed September 15, 2011.
(39) Incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed September 15, 2011.
(40) Incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed November 2, 2011.
(41) Incorporated by reference to Exhibit 2.1 to the Registrant's Form 8-K filed October 18, 2011.
(42) Incorporated by reference to Exhibit 2.1 to the Registrant's Form 8-K filed December 7, 2011.
(43) Incorporated by reference to Exhibit 2.1 to the Registrant's Form 8-K filed July 20, 2011.
(44) Incorporated by reference to Exhibit 1.1 to the Registrant's Form 8-K filed January 17, 2012.
(45) Incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed November 1, 2004.
(46) Incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed March 3, 2008.
(47) Incorporated by reference to Exhibit 10.1 to Exhibit 2.1 to Registrant's Form 8-K filed on January 13, 2012.
(48) Incorporated by reference to Exhibit 3.1 to Registrant's Form 8-K filed on March 28, 2012.
(49) Incorporated by reference to Exhibit 2.1 to Registrant's Form 8-K filed on May 1, 2012.
(50) Incorporated by reference to Exhibit 2.2 to Registrant's Form 8-K filed on June 20, 2012.
(51) Incorporated by reference to Exhibit 2.1 to Registrant's Form 8-K filed on June 20, 2012.
(52) Incorporated by reference to Exhibit 3.1 to Registrant's Form 8-K filed on March 28, 2012
(53) Incorporated by reference to Exhibit 3.1 to the Registrant's Form 8-K filed October 5, 2012.
(54) Incorporated by reference to Exhibit 3.2 to Registrant's Form 8-K filed on March 28, 2012.
(55) Incorporated by reference to Exhibit 3.3 to Registrant's Form 8-K filed on March 28, 2012.
(56) Incorporated by reference to Exhibit 4.2 to the Registrant's Form 8-K filed January 22, 2013.
(57) Incorporated by reference to Exhibit 4.1 to the Registrant's Form 8-K filed October 5, 2012.
(58) Incorporated by reference to Exhibit 4.2 to the Registrant's Form 8-K filed October 5, 2012.
(59) Incorporated by reference to Exhibit 4.3 to the Registrant's Form 8-K filed October 5, 2012.
(60) Incorporated by reference to Exhibit 4.4 to the Registrant's Form 8-K filed October 5, 2012.
(61) Incorporated by reference to Exhibit 4.7 to the Registrant's Form 8-K filed October 5, 2012.

(62) Incorporated by reference to Exhibit 4.8 to the Registrant's Form 8-K filed October 5, 2012.
(63) Incorporated by reference to Exhibit 4.9 to the Registrant's Form 8-K filed October 5, 2012.
(64) Incorporated by reference to Exhibit 10.1 to Registrant's Form 8-K filed on March 28, 2012.
(65) Incorporated by reference to Exhibit 10.2 to Registrant's Form 8-K filed on March 28, 2012.
(66) Incorporated by reference to Exhibit 10(t) to Southern Union's Annual Report on Form 10-K for the year ended December 31, 2006.
(67) Incorporated by reference to Exhibit 10(q) to Southern Union's Annual Report on Form 10-K for the year ended December 31, 2006.
(68) Incorporated by reference to Exhibit 10(r) to Southern Union's Annual Report on Form 10-K for the year ended December 31, 2006.
(69) Incorporated by reference to Exhibit 10.1 to Registrant's Form 8-K filed on January 13, 2012.
(70) Incorporated by reference to Exhibit 10.2 to Registrant's Form 8-K filed on January 13, 2012.
(71) Incorporated by reference to Exhibit 10.3 to Registrant's Form 8-K filed on January 13, 2012.
(72) Incorporated by reference to Exhibit 10.1 to Registrant's Form 8-K filed on May 1, 2012.
(73) Incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed December 17, 2012.
(74) Incorporated by reference to Exhibit 10.2 of the Registrant's Form 8-K filed on December 17, 2012.
(75) Incorporated by reference to Exhibit 99.1 to the Registrant's Form 10-Q filed on August 8, 2011.

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INDEX TO FINANCIAL STATEMENTS
Energy Transfer Partners, L.P. and Subsidiaries

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Partners
Energy Transfer Partners, L.P.

We have audited the accompanying consolidated balance sheets of Energy Transfer Partners, L.P. (a Delaware limited partnership) and subsidiaries (the "Partnership") as of December 31, 2012 and 2011, and the related consolidated statements of operations, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2012. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits. We did not audit the consolidated financial statements of Sunoco Logistics Partners L.P., a consolidated subsidiary, as of December 31, 2012 and for the period from October 5, 2012 to December 31, 2012, which statements reflect total assets constituting 24 percent of consolidated total assets as of December 31, 2012, and total revenues of 20 percent of consolidated total revenues for the year then ended. Those statements were audited by other auditors, whose report has been furnished to us, and our opinion, insofar as it relates to the amounts included for Sunoco Logistics Partners L.P., is based solely on the report of the other auditors.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits and the report of the other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audits and the report of the other auditors, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Energy Transfer Partners, L.P. and subsidiaries as of December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012 in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Partnership's internal control over financial reporting as of December 31, 2012, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 1, 2013 expressed an unqualified opinion thereon.

/s/ GRANT THORNTON LLP

Dallas, Texas
March 1, 2013

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PART I — FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS
ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Dollars in millions)

	December 31, 2012	2011
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$311	$107
Accounts receivable, net of allowance for doubtful accounts of $1 and $8 as of December 31, 2012 and 2011, respectively	2,910	569
Accounts receivable from related companies	94	82
Inventories	1,495	307
Exchanges receivable	55	19
Price risk management assets	21	11
Current assets held for sale	184	—
Other current assets	334	180
Total current assets	5,404	1,275
PROPERTY, PLANT AND EQUIPMENT	27,412	13,984
ACCUMULATED DEPRECIATION	(1,639)	(1,678)
	25,773	12,306
NON-CURRENT ASSETS HELD FOR SALE	985	—
ADVANCES TO AND INVESTMENTS IN UNCONSOLIDATED AFFILIATES	3,502	201
NON-CURRENT PRICE RISK MANAGEMENT ASSETS	42	26
GOODWILL	5,606	1,220
INTANGIBLE ASSETS, net	1,561	331
OTHER NON-CURRENT ASSETS, net	357	160
Total assets	$43,230	$15,519

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Dollars in millions)

	December 31, 2012	2011
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$3,002	$401
Accounts payable to related companies	24	33
Exchanges payable	156	18
Price risk management liabilities	110	80
Accrued and other current liabilities	1,562	630
Current maturities of long-term debt	609	424
Current liabilities held for sale	85	—
Total current liabilities	5,548	1,586
NON-CURRENT LIABILITIES HELD FOR SALE	142	—
LONG-TERM DEBT, less current maturities	15,442	7,388
LONG-TERM NOTES PAYABLE - RELATED PARTY	166	—
NON-CURRENT PRICE RISK MANAGEMENT LIABILITIES	129	42
DEFERRED INCOME TAXES	3,476	126
OTHER NON-CURRENT LIABILITIES	995	27
COMMITMENTS AND CONTINGENCIES (Note 10)		
EQUITY:		
General Partner	188	182
Limited Partners:		
Common Unitholders (301,485,604 and 225,468,108 units authorized, issued and outstanding as of December 31, 2012 and 2011, respectively)	9,026	5,533
Class E Unitholders (8,853,832 units authorized, issued and outstanding – held by subsidiary)	—	—
Class F Unitholders (90,706,000 units authorized, issued and outstanding – held by subsidiary)	—	—
Accumulated other comprehensive income (loss)	(13)	6
Total partners' capital	9,201	5,721
Noncontrolling interest	8,131	629
Total equity	17,332	6,350
Total liabilities and equity	$43,230	$15,519

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Dollars in millions, except per unit data)

	Years Ended December 31,		
	2012	2011	2010
REVENUES:			
Natural gas sales	$2,387	$2,534	$2,440
NGL sales	1,718	1,113	587
Crude sales	2,872	—	—