UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2013

OR

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

Commission file number 1-32740

ENERGY TRANSFER EQUITY, L.P.

(Exact name of registrant as specified in its charter)

Delaware	**30-0108820**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

3738 Oak Lawn Avenue, Dallas, Texas 75219
(Address of principal executive offices) (zip code)
Registrant's telephone number, including area code: **(214) 981-0700**

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

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

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days.
Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Yes ☒ No ☐

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

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

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

The aggregate market value as of June 28, 2013, 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 $12.59 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 21, 2014, the registrant had 558,235,474 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 Equity, L.P. (the "Partnership" or "ETE") 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," "project," "expect," "plan," "goal," "forecast," "estimate," "intend," "continue," "could," "believe," "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, estimated, projected, forecasted, expressed or expected 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 1.A 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 content
Canyon	ETC Canyon Pipeline, LLC
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., which owns 100% of FGT
CrossCountry	CrossCountry Energy, LLC
CFTC	Commodities Futures Trading Commission
DOT	U.S. Department of Transportation
Eagle Rock	Eagle Rock Energy Partners, LP
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
ETG	Energy Transfer Group, L.L.C.
ET Interstate	Energy Transfer Interstate Holdings, LLC
ETP	Energy Transfer Partners, L.P.

ETP Credit Facility	ETP's revolving credit facility
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
FDOT/FTE	Florida Department of Transportation, Florida's Turnpike Enterprise
FEP	Fayetteville Express Pipeline LLC
FERC	Federal Energy Regulatory Commission
FGT	Florida Gas Transmission Company, LLC, which owns a natural gas pipeline system that originates in Texas and delivers natural gas to the Florida peninsula
GAAP	accounting principles generally accepted in the United States of America
General Partner	LE GP, LLC, the general partner of ETE
HPC	RIGS Haynesville Partnership Co.
Holdco	ETP Holdco Corporation
HOLP	Heritage Operating, L.P.
Hoover Energy	Hoover Energy Partners, LP
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
LNG Holdings	Trunkline LNG Holdings, LLC
LPG	liquefied petroleum gas
Lone Star	Lone Star NGL LLC
MACS	Mid-Atlantic Convenience Stores
MEP	Midcontinent Express Pipeline LLC
MGE	Missouri Gas Energy
MGP	manufactured gas plant
MMBtu	million British thermal units
MMcf	million cubic feet
NGA	Natural Gas Act of 1938
NGPA	Natural Gas Policy Act of 1978
NEG	New England Gas Company
NGL	natural gas liquid, such as propane, butane and natural gasoline
NMED	New Mexico Environmental Department
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
OSHA	Federal Occupational Safety and Health Act

Panhandle	Panhandle Eastern Pipe Line Company, LP and its subsidiaries
PCB	polychlorinated biphenyl
PEPL	Panhandle Eastern Pipe Line Company, LP
PEPL Holdings	PEPL Holdings, LLC, a wholly-owned subsidiary of Southern Union, which owned the general partner and 100% of the limited partner interests in PEPL
PES	Philadelphia Energy Solutions
PHMSA	Pipeline Hazardous Materials Safety Administration
PVR	PVR Partners, L.P.
RIGS	Regency Intrastate Gas System
RGS	Regency Gas Services, a wholly-owned subsidiary of Regency
Preferred Units	ETE’s Series A Convertible Preferred Units
Ranch JV	Ranch Westex JV LLC
Regency	Regency Energy Partners LP
Regency GP	Regency GP LP, the general partner of Regency
Regency LLC	Regency GP LLC, the general partner of Regency GP
Regency Preferred Units	Regency’s Series A Convertible Preferred Units, the Preferred Units of a Subsidiary
Sea Robin	Sea Robin Pipeline Company, LLC
SEC	Securities and Exchange Commission
Southern Union	Southern Union Company
Southwest Gas	Pan Gas Storage, LLC
SUGS	Southern Union Gas Services
Sunoco	Sunoco, Inc.
Sunoco Logistics	Sunoco Logistics Partners L.P.
Sunoco Partners	Sunoco Partners LLC, the general partner of Sunoco Logistics
TCEQ	Texas Commission on Environmental Quality
Titan	Titan Energy Partners, L.P.
Transwestern	Transwestern Pipeline Company, LLC
TRRC	Texas Railroad Commission
Trunkline	Trunkline Gas Company, LLC
Trunkline LNG	Trunkline LNG Company, LLC
WTI	West Texas Intermediate Crude

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.

PART I
ITEM 1. BUSINESS

Overview

We were formed in September 2002 and completed our initial public offering in February 2006. We are a Delaware limited partnership with common units publicly traded on the NYSE under the ticker symbol "ETE."

Unless the context requires otherwise, references to "we," "us," "our," the "Partnership" and "ETE" mean Energy Transfer Equity, L.P. and its consolidated subsidiaries, which include ETP, ETP GP, ETP LLC, Regency, Regency GP, Regency LLC, Panhandle (or Southern Union prior to its merger into Panhandle in January 2014), Sunoco, Sunoco Logistics and Holdco. References to the "Parent Company" mean Energy Transfer Equity, L.P. on a stand-alone basis.

In January 2014, the Partnership completed a two-for-one split of its outstanding common units. All references to units and per unit amounts in this document have been adjusted to reflect the effect of the unit split for all periods presented.

On March 26, 2012, we acquired all of the outstanding shares of Southern Union and contributed our ownership in Southern Union for a 60% interest in Holdco at the time of ETP's acquisition of Sunoco on October 5, 2012. On April 30, 2013, ETP acquired ETE's 60% interest in Holdco.

The Parent Company's principal sources of cash flow are derived from its direct and indirect investments in the limited partner and general partner interests in ETP and Regency, both of which are publicly traded master limited partnerships engaged in diversified energy-related services.

At December 31, 2013, our interests in ETP and Regency consisted of 100% of the respective general partner interests and IDRs, as well as the following:

	ETP	Regency
Units held by wholly-owned subsidiaries:		
Common units	49,551,069	26,266,791
ETP Class H units	50,160,000	—
Units held by less than wholly-owned subsidiaries:		
Common units	—	31,372,419
Regency Class F units	—	6,274,483

The Parent Company's primary cash requirements are for distributions to its partners, general and administrative expenses, debt service requirements and at ETE's election, capital contributions to ETP and Regency in respect of ETE's general partner interests in ETP and Regency. The Parent Company-only assets and liabilities are not available to satisfy the debts and other obligations of subsidiaries.

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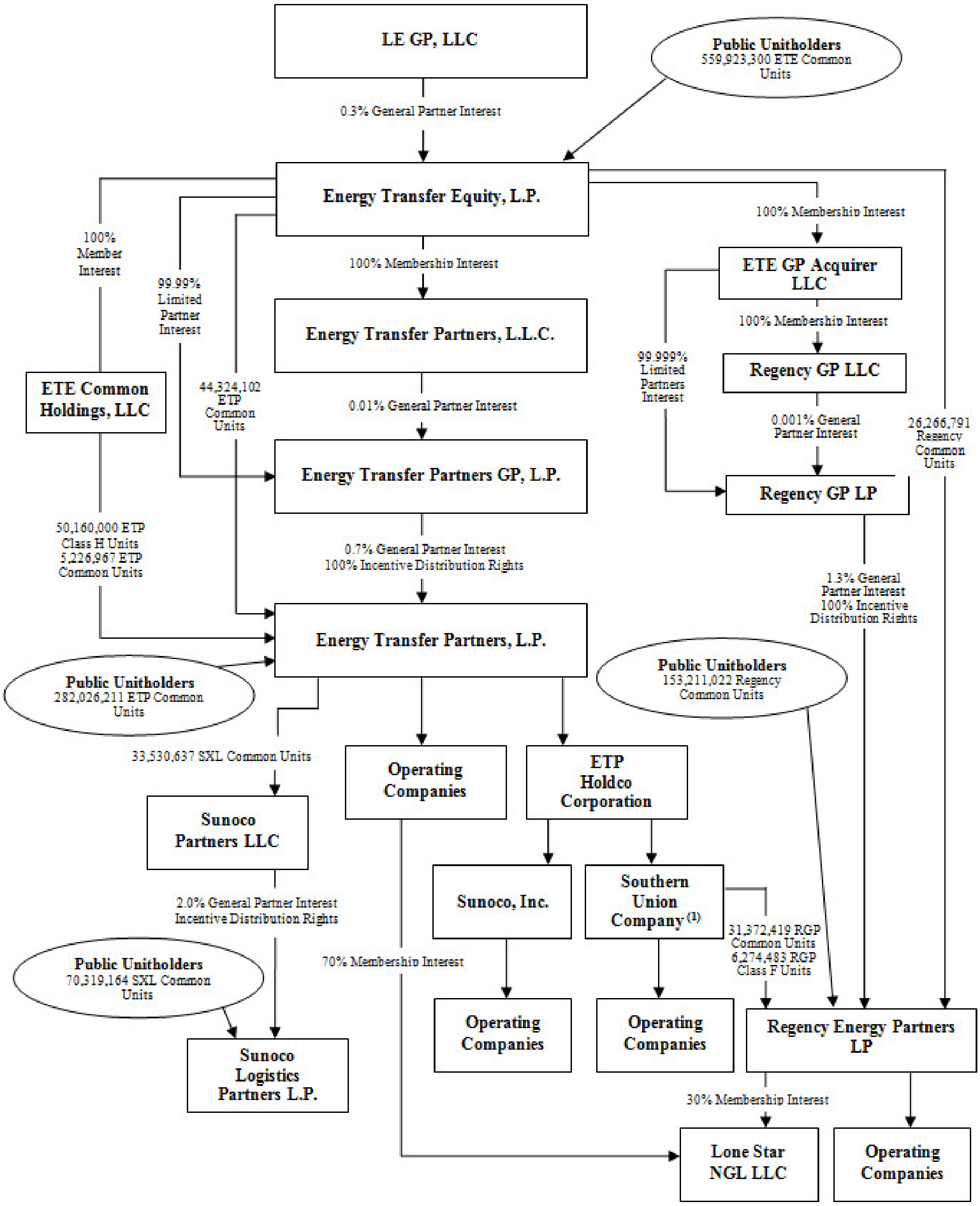
Organizational Structure

The following chart summarizes our organizational structure as of December 31, 2013. For simplicity, certain immaterial entities and ownership interests have not been depicted.



(1) On January 10, 2014, as part of our effort to simplify our structure, Panhandle consummated a merger with Southern Union, the indirect parent of Panhandle, and PEPL Holdings, the sole limited partner of Panhandle, pursuant to which each of Southern Union and PEPL Holdings were merged with and into Panhandle, with Panhandle as the surviving entity.

Strategic Transactions

Our significant strategic transactions in 2013 and beyond included the following, as discussed in more detail herein:

- On April 30, 2013, Southern Union completed its contribution to Regency of all of the issued and outstanding membership interest in Southern Union Gathering Company, LLC, and its subsidiaries, including SUGS. The consideration paid by Regency in connection with this transaction consisted of (i) the issuance of approximately 31.4 million Regency common units to Southern Union, (ii) the issuance of approximately 6.3 million Regency Class F units to Southern Union, (iii) the distribution of $463 million in cash to Southern Union, net of closing adjustments, and (iv) the payment of $30 million in cash to a subsidiary of ETP.

- On April 30, 2013, ETP acquired ETE's 60% interest in Holdco for approximately 49.5 million of newly issued ETP Common Units and $1.40 billion in cash, less $68 million of closing adjustments (the "Holdco Acquisition"). As a result, ETP now owns 100% of Holdco. ETE, agreed to forego incentive distributions on the newly issued ETP units for each of the first eight consecutive quarters beginning with the quarter in which the closing of the transaction occurred and 50% of incentive distributions on the newly issued ETP units for the following eight consecutive quarters. ETP controlled Holdco prior to this acquisition; therefore, the transaction did not constitute a change of control.

- On June 24, 2013, ETP completed the exchange of approximately $1.09 billion aggregate principal amount of Southern Union's outstanding senior notes, comprising 77% of the principal amount of the 7.6% Senior Notes due 2024, 89% of the principal amount of the 8.25% Senior Notes due 2029 and 91% of the principal amount of the Junior Subordinated Notes due 2066. These notes were exchanged for new notes issued by ETP with the same coupon rates and maturity dates.

- On July 12, 2013, ETP received $346 million in net proceeds from the sale of 7.5 million of its AmeriGas common units, which were received in connection with the Partnership's contribution of its retail propane operations to AmeriGas in January 2012. In January 2014, ETP sold 9.2 million AmeriGas common units for net proceeds of $381 million.

- In September 2013, Southern Union completed its sale of the assets of MGE for an aggregate purchase price of $975 million, net of customary post-closing adjustments. In December 2013, Southern Union completed its sale of the assets of NEG for cash proceeds of $40 million, net of customary post-closing adjustments, and the assumption of $20 million of debt.

- In October 2013, La Grange Acquisition, L.P., an indirect wholly-owned subsidiary of ETP, acquired convenience store operator MACS with a network of approximately 300 company-owned and dealer locations. These operations were reflected in ETP's retail marketing operations, along with the retail marketing operations owned by Sunoco, beginning in the fourth quarter of 2013.

- On October 31, 2013, ETP and ETE exchanged 50.2 million ETP Common Units, owned by ETE, for newly issued Class H Units by ETP that track 50% of the underlying economics of the general partner interest and the IDRs of Sunoco Logistics.

- In December 2013, ETE completed a tender offer for a portion of its outstanding 7.50% Senior Notes due 2020. In conjunction with the tender offer, ETE completed a comprehensive refinancing of its existing debt, which included the public offering of $450 million aggregate principal amount of its 5.875% Senior Notes due 2024, a new $1 billion term loan facility, and a new $600 million revolving credit facility. In February 2014, ETE increased the capacity on the ETE Revolving Credit Facility to $800 million and expects to utilize the additional capacity to fund the purchase of $400 million of Regency common units in connection with Regency's pending Eagle Rock acquisition.

- On January 10, 2014, as part of our effort to simplify our structure, Panhandle consummated a merger with Southern Union, the indirect partner of Panhandle, and PEPL Holdings, the sole limited partner of Panhandle, pursuant to which each of Southern Union and PEPL Holdings were merged with and into Panhandle, with Panhandle as the surviving entity.

- On February 19, 2014, ETE and ETP completed the transfer to ETE of Trunkline LNG, the entity that owns a LNG regasification facility in Lake Charles, Louisiana, from ETP in exchange for the redemption by ETP of 18.7 million ETP Common Units held by ETE. This transaction was effective as of January 1, 2014.

- In October 2013, Regency entered into a merger agreement with PVR pursuant to which Regency intends to merge with PVR. This merger will be a unit-for-unit transaction plus a one-time $37 million cash payment to PVR unitholders which represents total consideration of $5.6 billion, including the assumption of net debt of $1.8 billion. The PVR Acquisition is expected to enhance our geographic diversity with a strategic presence in the Marcellus and Utica shales in the Appalachian Basin and the Granite Wash in the Mid-Continent region. The PVR Acquisition is expected to close in late March 2014, subject to receipt of the affirmative vote of a majority of the PVR common units outstanding at a meeting scheduled to be held on March 20, 2014 and subject to the satisfaction of other customary closing conditions.

- In December, 2013, Regency entered into an agreement to purchase Eagle Rock's midstream business for $1.3 billion. This acquisition is expected to complement Regency's core gathering and processing business and further diversify Regency's basin exposure in the Texas Panhandle, East Texas and South Texas. The Eagle Rock Midstream Acquisition is expected to close in the second quarter of 2014.

- On February 3, 2014, Regency completed its acquisition of the subsidiaries (the "acquired Hoover entities") of Hoover Energy that are engaged in crude oil gathering, transportation and terminalling, condensate handling, natural gas gathering, treating and processing, and water gathering and disposal services in the southern Delaware Basin in West Texas. The consideration paid by Regency in exchange for the acquired Hoover entities was valued at $282 million (subject to customary post-closing adjustments) and consisted of (i) 4.0 million Regency Common Units issued to Hoover Energy and (ii) $184 million in cash. A portion of the consideration is being held in escrow as security for certain indemnification claims. Regency financed the cash portion of the purchase price through borrowings under its revolving credit facility.

Business Strategy

Our primary business objective is to increase cash available for distributions to our unitholders by actively assisting our subsidiaries in executing their business strategies by assisting in identifying, evaluating and pursuing strategic acquisitions and growth opportunities. In general, we expect that we will allow our subsidiaries the first opportunity to pursue any acquisition or internal growth project that may be presented to us which may be within the scope our their operations or business strategies. In the future, we may also support the growth of our subsidiaries through the use of our capital resources which could involve loans, capital contributions or other forms of credit support to our subsidiaries. This funding could be used for the acquisition by one of our subsidiaries of a business or asset or for an internal growth project. In addition, the availability of this capital could assist our subsidiaries in arranging financing for a project, reducing its financing costs or otherwise supporting a merger or acquisition transaction.

Segment Overview

As a result of the Holdco Acquisition in April 2013, our reportable segments were re-evaluated and currently reflect the following reportable segments:

- Investment in ETP, including the consolidated operations of ETP;
- Investment in Regency, including the consolidated operations of Regency; and
- Corporate and Other, including the following:
  - activities of the Parent Company; and
  - the goodwill and property, plant and equipment fair value adjustments recorded as a result of the 2004 reverse acquisition of Heritage Propane Partners, L.P.

The businesses within these segments are described below. See Note 15 to our consolidated financial statements for additional financial information about our reportable segments.

Investment in ETP

ETP's operations include the following:

Intrastate Transportation and Storage Operations

ETP's 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 its intrastate transportation and storage Operations, ETP owns and operates approximately 7,800 miles of natural gas transportation pipelines with approximately 14.0 Bcf/d of transportation capacity and three natural gas storage facilities located in the state of Texas.

ETP 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. In addition, ETP's intrastate transportation and storage operations generate revenues from fees charged for storing customers' working natural gas in ETP's storage facilities and from margin from managing natural gas for its own account.

Interstate Transportation and Storage Operations

ETP's 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 its interstate transportation and storage operations, ETP directly owns and operates approximately 12,800 miles of interstate natural gas pipeline with approximately 11.3

Bcf/d of transportation capacity and has 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.

ETP's interstate transportation and storage operations include Panhandle, which 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.

Midstream Operations

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.

Through ETP's midstream operations, ETP owns and operates approximately 6,700 miles of in service natural gas and NGL gathering pipelines with approximately 6.0 Bcf/d of gathering capacity, 5 natural gas processing plants, 15 natural gas treating facilities and 3 natural gas conditioning facilities. ETP's midstream operations focus on the gathering, compression, treating, blending, and processing, 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 ETP's midstream assets are integrated with its intrastate transportation and storage assets.

NGL Transportation and Services Operations

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 ETP's NGL transportation and services operations ETP has a 70% interest in Lone Star, which owns approximately 2,000 miles of NGL pipelines with an aggregate transportation capacity of approximately 388,000 Bbls/d, three NGL processing plants with an aggregate processing capacity of approximately 904 MMcf/d, three fractionation facilities with an aggregate capacity of 251,000 Bbls/d and NGL storage facilities with aggregate working storage capacity of approximately 47 million Bbls. Two fractionation facilities and the NGL storage facilities are located at Mont Belvieu, Texas, one fractionation facility is located in Geismar, Louisiana, and the NGL pipelines primarily transport NGLs from the Permian and Delaware basins and the Barnett and Eagle Ford Shales to Mont Belvieu. ETP also owns and operates approximately 274 miles of NGL pipelines including a 50% interest in the Liberty pipeline, an approximately 87-mile NGL pipeline.

ETP's Investment in Sunoco Logistics

ETP's interests in Sunoco Logistics consist of a 2% general partner interest, 100% of the IDRs and 33.5 million Sunoco Logistics common units representing 32% of the limited partner interests in Sunoco Logistics as of December 31, 2013. Because ETP controls Sunoco Logistics through its ownership of the general partner, the operations of Sunoco Logistics are consolidated into the Partnership.

Sunoco Logistics owns and operates a logistics business, consisting of a geographically diverse portfolio of complementary pipeline, terminalling, and acquisition and marketing assets which are used to facilitate the purchase and sale of crude oil and refined petroleum products pipelines primarily in the northeast, midwest and southwest regions of the United States. In 2013, Sunoco Logistics initiated the expansion of its operations into the pipeline transportation, acquisition, storage and marketing of NGLs. In addition, Sunoco Logistics has ownership interests in several refined product pipeline joint ventures.

Sunoco Logistics' crude oil pipelines transport crude oil principally in Oklahoma and Texas. 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 300 crude oil transport trucks, approximately 130 crude oil truck unloading facilities as well as third-party assets.

Sunoco Logistics' refined products terminals receive refined products from pipelines, barges, railcars, and trucks and distribute them to third parties and certain affiliates, who in turn deliver them to end-users and retail outlets. Sunoco Logistics' terminal facilities operate with an aggregate storage capacity of approximately 46 million barrels, including the 22 million barrel Nederland, Texas crude oil terminal; the 5 million barrel Eagle Point, New Jersey refined products and crude oil terminal; the 5 million barrel Marcus Hook, Pennsylvania refined products and NGL facility; approximately 39 active refined 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 Operations

ETP's retail marketing and wholesale distribution business operations consists of the following:

- Retail marketing operations consist of the sale of gasoline and middle distillates at retail locations and operation of convenience stores in 24 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.
- Sunoco also engages in the distribution of gasoline (including gasoline blendstocks such as ethanol), distillates, and other petroleum products to wholesalers, retailers and other commercial customers.

ETP's All Other Operations and Investments

ETP's other operations and investments include the following:

- ETP owns 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 ETP's other operations.
- ETP owns 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.
- ETP owns common units in AmeriGas, a publicly traded company engaged in retail propane marketing. ETP acquired this interest when it contributed its retail propane operations to AmeriGas in January 2012. As of December 31, 2013, ETP owned common units representing approximately 24% of AmeriGas' outstanding common units and, following a sale of a portion of these units in a public offering in January 2014, ETP owns 12.9 million AmeriGas common units representing approximately 14% of AmeriGas' outstanding common units.
- Southern Union previously had operations providing local distribution of natural gas in Missouri and Massachusetts. The operations were conducted through the Southern Union's operating divisions: MGE and NEG. Both of these operating divisions were disposed of in 2013.
- Sunoco owns an approximate 33% non-operating interest in PES, a refining joint venture with The Carlyle Group, L.P. ("The Carlyle Group"), which owns a refinery in Philadelphia. Sunoco has a supply contract for gasoline and diesel produced at the refinery for its retail marketing business.
- ETP owns an investment in Regency related to the Regency common and Class F units received by Southern Union in exchange of its interest in Southern Union Gathering Company, LLC to Regency on April 30, 2013.
- ETP conducts marketing operations in which it markets the natural gas that flows through its gathering and intrastate transportation assets, referred to as on-system gas.

Investment in Regency

Regency's operations include the following:

Gathering and Processing Operations

Regency provides "wellhead-to-market" services to producers of natural gas, which include transporting raw natural gas from the wellhead through gathering systems, processing raw natural gas to separate NGLs from the raw natural gas and selling or delivering the pipeline-quality natural gas and NGLs to various markets and pipeline systems, and the gathering of oil (crude and/or condensate, a lighter oil) received from producers. These operations also include Edwards Lime Gathering LLC and Regency's 33.33% membership interest in Ranch JV, which processes natural gas delivered from the NGLs-rich Bone Spring and Avalon shale formations in West Texas. Regency completed its acquisition of SUGS on April 30, 2013 which was a transaction between entities under common control. Therefore, Regency's Gathering and Processing operations amounts have been retrospectively adjusted to reflect the SUGS Acquisition beginning March 26, 2012, the date upon which common control began.

Natural Gas Transportation Operations

Regency owns a 49.99% general partner interest in HPC, which owns RIGS, a 450-mile intrastate pipeline that delivers natural gas from northwest Louisiana to downstream pipelines and markets, and a 50% membership interest in MEP, which owns a 500-mile interstate natural gas pipeline stretching from southeast Oklahoma through northeast Texas, northern Louisiana and central Mississippi to an interconnect with the Transcontinental Gas Pipe Line system in Butler, Alabama. These operations also include Gulf States, which owns a 10-mile interstate pipeline that extends from Harrison County, Texas to Caddo Parish, Louisiana.

NGL Services Operations

Regency owns a 30% membership interest in Lone Star with ETP owning the remaining 70% membership interest.

Contract Services Operations

Regency owns and operates a fleet of compressors used to provide turn-key natural gas compression services for customer specific systems. Regency also owns and operates a fleet of equipment used to provide treating services, such as carbon dioxide and hydrogen sulfide removal, natural gas cooling and dehydration.

Asset Overview

Investment in ETP

The following details the assets in ETP's operations:

Intrastate Transportation and Storage

The following details pipelines and storage facilities in ETP's intrastate transportation and storage operations:

ET Fuel System

- Capacity of 5.2 Bcf/d
- Approximately 2,870 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 prolific production areas in the United States and is comprised of intrastate natural gas pipeline and related natural gas storage facilities. The ET Fuel System has many interconnections with pipelines providing direct access to power plants, other intrastate and interstate pipelines and 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 ET Fuel System also includes ETP's 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 ETP's 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 ETP's storage capacity on the ET Fuel System is contracted to third parties under fee-based arrangements that extend through 2015.

In addition, the ET Fuel System is integrated with ETP's Godley processing plant which gives ETP 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 ETP's Southeast Texas System and is an important component to maximizing ETP's 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 ETP to bypass ETP's processing plants and treating facilities on the Southeast Texas System when processing margins are unfavorable by blending untreated natural gas from the Southeast Texas System with gas on the Oasis pipeline while continuing to meet pipeline quality specifications.

HPL System

- Capacity of 5.3 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 ETP 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 ETP's 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, 2013, ETP had approximately 7.2 Bcf committed under fee-based arrangements with third parties and approximately 45.8 Bcf stored in the facility for ETP's own account.

ETP is currently converting approximately 84 miles of pipeline from the HPL System to crude service. This project is expected to be completed in 2014.

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 ETP owns, with ETP's 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 ETP's Reed compressor station in Freestone County to ETP's Grimes County compressor station, the 36-inch Katy expansion connecting Grimes to the Katy Hub, and the 42-inch Southeast Bossier pipeline connecting ETP's Cleburne to Carthage pipeline to the HPL System.

Interstate Transportation and Storage

The following details ETP's pipelines in the interstate transportation and storage operations.

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 63% of the natural gas consumed in the state. In addition, Florida Gas Transmission's pipeline system operates and maintains over 75 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 2.1 Bcf/d
- Approximately 2,600 miles of interstate natural gas pipeline
- Bi-directional capabilities

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

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

Panhandle Eastern Pipe Line

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

The Panhandle Eastern Pipe Line'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 Pipe Line 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
- Bi-directional capabilities

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.

ETP is currently developing plans to convert a portion of the Trunkline gas pipeline to crude oil transportation.

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 ETP's 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 LP

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 2.3 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 120 miles into the Gulf of Mexico.

Midstream

The following details ETP assets in its midstream operations:

Southeast Texas System

- Approximately 5,900 miles of natural gas pipeline
- One natural gas processing plant (La Grange) with aggregate capacity of 210 MMcf/d
- 11 natural gas treating facilities with aggregate capacity of 1.4 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 ETP to bypass 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 ETP's system to produce residue gas and NGLs. Residue gas is delivered into ETP's intrastate pipelines and NGLs are delivered into ETP's recently acquired or completed pipelines.

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

North Texas System

- Approximately 160 miles of natural gas pipeline
- One natural gas processing plant (the Godley plant) with aggregate capacity of 700 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 ETP's 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

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

Eagle Ford System

- Approximately 245 miles of natural gas pipeline
- Three processing plants (Chisholm, Kenedy and Jackson) with capacity of 920 MMcf/d
- One natural gas treating facility with capacity of 300 MMcf/d

The Eagle Ford gathering system consists of 30-inch and 42-inch natural gas transportation pipelines delivering 1.4 Bcf/d of capacity originating in Dimmitt County, Texas and extending to ETP's Chisholm pipeline for ultimate deliveries to ETP existing processing plants. The Chisholm, Kenedy and Jackson processing plants are connected to ETP's intrastate transportation pipeline systems for deliveries of residue gas and are also connected with ETP NGL pipelines for delivery of NGLs.

Other Midstream Assets

The midstream operations also include ETP's interests in various midstream assets located in Texas, New Mexico and Louisiana, with approximately 60 miles of gathering pipelines aggregating a combined capacity of approximately 115 MMcf/d, as well as one conditioning facility. ETP also owns approximately 35 miles of gathering pipelines serving the Marcellus Shale in West Virginia with aggregate capacity of approximately 250 MMcf/d.

NGL Transportation and Services

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

West Texas System

- Capacity of 137,000 Bbls/d
- Approximately 1,070 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 processing plants in the Permian Basin and Barnett Shale to the Mont Belvieu NGL storage facility.

West Texas Gateway Pipeline

- 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 and the Eagle Ford Shale to Mont Belvieu, Texas.

Other NGL Pipelines

- Aggregate capacity of 490,000 Bbls/d
- Approximately 274 miles of NGL transmission pipelines

Other NGL pipelines include the 127-mile Justice pipeline with capacity of 340,000 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 15-mile Spirit pipeline with a capacity of 20,000 Bbls/d.

Mont Belvieu Facilities

- Working storage capacity of approximately 43 million Bbls
- Approximately 185 miles of NGL transmission pipelines
- 200,000 Bbls/d fractionation facilities

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 Lone Star Fractionators I and II, completed in December 2012 and November 2013, respectively, handle NGLs delivered from several sources, including Lone Star's West Texas Gateway pipeline and the Justice pipeline.

Hattiesburg Storage Facility

- Working storage capacity of approximately 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 (Chalmette and Sorrento) with capacity of 54 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 Chalmette processing plant.

Investment in Sunoco Logistics

The following details ETP's assets in its investment in 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:

- *Southwest United States:* The Southwest United States pipeline system includes approximately 2,950 miles of crude oil trunk pipelines and approximately 300 miles of crude oil gathering pipelines in Texas. The Texas system includes the West Texas Gulf Pipe Line Company's 600 miles of common carrier crude oil pipelines, which originate from the West Texas oil fields at Colorado City, Texas and is connected to the Mid-Valley pipeline, other third-party pipelines and the Nederland Terminal.

  The Southwest United States pipeline system also includes the Oklahoma crude oil pipeline and gathering system that consists of approximately 850 miles of crude oil trunk pipelines and approximately 200 miles of crude oil gathering pipelines. Sunoco Logistics has the ability to deliver substantially all of the crude oil gathered on the Oklahoma system to Cushing, Oklahoma and is one of the largest purchasers of crude oil from producers in the state.

- *Midwest United States:* The Midwest United States pipeline system includes Sunoco Logistics' majority interest in the Mid-Valley Pipeline Company and 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.

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 300 crude oil transport trucks, approximately 130 crude oil truck unloading facilities, as well as third-party assets. Sunoco Logistics' crude oil truck drivers pick up crude oil at production lease sites and transport it to various truck unloading facilities on its pipelines and third-party pipelines. Third-party trucking firms are also retained to transport crude oil to certain facilities. Specifically, the crude oil acquisition and marketing activities include:

- purchasing crude oil at the wellhead from producers, and in bulk from aggregators at major pipeline interconnections and trading locations;
- storing inventory during contango market conditions (when the price of crude oil for future delivery is higher than current prices);
- buying and selling crude oil of different grades, at different locations in order to maximize value for producers;
- transporting crude oil on Sunoco Logistics' pipelines and trucks or, when necessary or cost effective, pipelines or trucks owned and operated by third parties; and
- marketing crude oil to major integrated oil companies, independent refiners and resellers through various types of sale and exchange transactions.

Terminal Facilities

Sunoco Logistics' 39 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.

- *Nederland Terminal:* The 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 above ground storage tanks with individual capacities of up to 660,000 barrels.

  The Nederland Terminal can receive crude oil at each of its five ship docks and three barge berths. The five ship docks are capable of receiving over 2 million Bbls/d of crude oil. In addition to Sunoco Logistics' Crude Oil Pipelines, the terminal can also receive crude oil through a number of other pipelines, including: the Cameron Highway pipeline, which is jointly owned by Enterprise Products and Genesis Energy; the ExxonMobil Pegasus pipeline; the Department of Energy ("DOE") Big Hill pipeline; and the DOE West Hackberry pipeline. The DOE pipelines connect the terminal to the United States Strategic Petroleum Reserve's West Hackberry caverns at Hackberry, Louisiana and Big Hill near Winnie, Texas, which have an aggregate storage capacity of approximately 400 million barrels.

  The Nederland Terminal can deliver crude oil and other petroleum products via pipeline, barge, ship, rail, or truck. In total, the terminal is capable of delivering over 2 million Bbls/d of crude oil to Sunoco Logistics' crude oil pipelines or a number of third-party pipelines including: the ExxonMobil pipeline to its Beaumont, Texas refinery; the DOE pipelines to the Big

Hill and West Hackberry Strategic Petroleum Reserve caverns; the Valero pipeline to its Port Arthur, Texas refinery; and the Total pipelines to its Port Arthur, Texas refinery.

- *Fort Mifflin Terminal Complex:* The Fort Mifflin Terminal Complex is located on the Delaware River in Philadelphia, Pennsylvania 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. The Fort Mifflin Terminal contains two ship docks with 40-foot freshwater drafts and a total storage capacity of approximately 570,000 barrels. Crude oil and some refined products enter the Fort Mifflin Terminal primarily from marine vessels on the Delaware River. One Fort Mifflin dock is designed to handle crude oil from very large crude carrier-class ("VLCC") tankers and smaller crude oil vessels. The other dock can accommodate only smaller crude oil vessels. In September 2012, Sunoco completed the formation of PES, a joint venture with The Carlyle Group. In connection with this transaction, Sunoco Logistics entered into a ten-year agreement to provide terminalling services to PES at the Fort Mifflin Terminal Complex.

  The Hog Island Wharf is located next to the Fort Mifflin Terminal on the Delaware River and receives crude oil via two ship docks, one of which can accommodate crude oil tankers and smaller crude oil vessels, and the other of which can accommodate some smaller crude oil vessels.

  The Darby Creek tank farm is a primary crude oil storage terminal for the Philadelphia refinery. This facility has a total storage capacity of approximately 3 million barrels. Darby Creek receives crude oil from the Fort Mifflin Terminal and Hog Island Wharf via Sunoco Logistics pipelines. The tank farm then stores the crude oil and transports it to the PES refinery via Sunoco Logistics pipelines.

- *Marcus Hook Facility:* In 2013, Sunoco Logistics acquired Sunoco's Marcus Hook facility and related assets. The acquisition included terminalling and storage assets located in Pennsylvania and Delaware, including approximately 5 million barrels of NGL storage capacity in underground caverns, and related commercial agreements. The facility can receive NGLs via marine vessel, pipeline, truck and rail, and can deliver via marine vessel, pipeline and truck. In addition to providing NGL storage and terminalling services to both affiliates and third-party customers, the Marcus Hook facility also provides customers with the use of industrial space and equipment at the facility, as well as logistical, utility and infrastructure services.

  The Marcus Hook tank farm has a total storage capacity of approximately 2 million barrels. The terminal generates revenue from throughput and storage, and delivers and receives refined products via pipeline. Sunoco Logistics utilizes the tank farm assets to provide terminalling services and to support movements on its refined products pipelines.

- *Eagle Point Terminal:* The Eagle Point Terminal is located in Westville, New Jersey and consists of docks, truck loading facilities and a tank farm. The docks are located on the Delaware River and can accommodate three ships or barges to receive and deliver crude oil, intermediate products and refined products to outbound ships and barges. The tank farm has a total active storage capacity of approximately 5 million barrels and can receive crude oil and refined products via barge, pipeline and rail. The terminal can deliver via barge, truck, rail or pipeline, providing customers with access to various markets. The terminal generates revenue primarily by charging fees based on throughput, blending services and storage for clean products and dark oils.

- *Inkster Terminal:* The 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.

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
Louisiana	1	161
Maryland	1	710
Massachusetts	1	1,144
Michigan	3	760
New Jersey	3	650
New York[1]	4	920
Ohio	7	957
Pennsylvania	13	1,743
Texas	4	548
Virginia	1	403
Total	39	8,202

(1) Sunoco Logistics has 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.

Refined Products Pipelines

Sunoco Logistics owns and operates approximately 2,500 miles of refined products pipelines in several regions of the United States. The refined products pipelines primarily transport refined products from refineries in the northeast, midwest and southwest United States to markets in New York, New Jersey, Pennsylvania, Ohio, Michigan and Texas. These pipelines include the approximately 350 miles of pipelines owned by Sunoco Logistics' consolidated joint venture, Inland.

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). In addition, certain of these pipelines transport NGLs from processing and fractionation areas to marketing and distribution facilities. 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.

- *Inland Corporation:* Inland Corporation ("Inland") is Sunoco Logistics' 83.8% owned joint venture consisting of approximately 350 miles of active refined products pipelines in Ohio. The pipeline connects three refineries in Ohio to terminals and major markets within the state. As Sunoco Logistics owns a 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 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.

Retail Marketing

ETP's retail marketing operations consists of the retail sale of gasoline and middle distillates and the operation of Sunoco and MACS convenience stores in 24 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 (either directly or through a wholly-owned subsidiary of ETC OLP) 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. Some of these sites may be traditional locations that sell fuel products under the Sunoco®, Exxon®, Mobil® and Coastal® brands. The site may also include APlus® or Circle K® convenience store or Ultra Service Centers® that provide automotive diagnostics and repair. Included among the direct outlets at December 31, 2013 were 74 outlets on turnpikes and expressways in Pennsylvania, New Jersey, New York, Maryland, Ohio and Delaware. Of these outlets, 59 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.

The following table sets forth ETP's retail gasoline outlets at December 31, 2013 (including sites operated through Sunoco and a wholly-owned subsidiary of ETC OLP):

Direct Outlets:	
Company-Owned or Leased:	
Company Operated:	
Traditional	66
APlus® and Circle K® Convenience Stores	447
	513
Dealer Operated:	
Traditional	252
APlus® and Circle K® Convenience Stores	241
Ultra Service Centers®	83
	576
Total Company-Owned or Leased(1)	1,089
Dealer Owned(2)	525
Total Direct Outlets	1,614
Distributor Outlets	3,498
	5,112

(1) Gasoline and diesel throughput per company-operated site averaged 200,087 gallons per month during 2013.

(2) Primarily traditional outlets.

Sunoco's branded fuels sales (including middle distillates) averaged 315,700 Bbls/d in 2013.

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, 2013:

Number of stores		384
Merchandise sales (thousands of dollars/store/month)	$	108
Merchandise margin (% sales)		26.8%

The retail marketing operations also include the distribution of gasoline, distillates and other petroleum products to wholesalers, unbranded retailers and other commercial customers.

Investment in Regency

The following details the assets in Regency's natural gas operations:

Gathering and Processing Operations

North Louisiana Region

- Approximately 1,201 miles of natural gas pipeline
- Two cryogenic natural gas processing facilities, a refrigeration plant, a conditioning plant and two amine treating plants

Regency's North Louisiana assets gather, compress, treat and dehydrate natural gas in five Parishes (Claiborne, Union, DeSoto, Lincoln and Ouachita) of north Louisiana and Shelby County, Texas. Its assets also include two cryogenic natural gas processing facilities, a refrigeration plant located in Bossier Parish, a conditioning plant located in Webster Parish, an amine treating plant in DeSoto Parish, an amine treating plant in Lincoln Parish, and an interstate NGL pipeline.

In the second quarter of 2013, Regency placed into service an expansion of the Dubach processing facility in North Louisiana that increased the processing capacity of the system to 210 MMcf/d and added high-pressure gathering lines to bring production to the facility.

In mid-2013, Regency began an expansion project to increase the gathering capacity of Regency's Dubberly facility by 400 MMcf/d and a 200 MMcf/d processing upgrade, for $68 million, which is expected to be completed in early 2014.

Through the gathering and processing systems described above and their interconnections with RIGS in North Louisiana, Regency offers producers wellhead-to-market services, including natural gas gathering, compression, processing, treating and transportation.

South Texas Region

- Approximately 1,310 miles of natural gas pipeline
- Three treating plants

Regency's South Texas assets gather, compress, treat and dehydrate natural gas in Bee, LaSalle, Webb, Karnes, Atascosa, McMullen, Frio and Dimmitt counties. Some of the natural gas produced in this region can have significant quantities of hydrogen sulfide and carbon dioxide that require treating to remove these impurities. The pipeline systems that gather this gas are connected to third-party processing plants and Regency's treating facilities that include an acid gas reinjection well located in McMullen County, Texas. Regency also gathers oil for producers in the region and delivers it to tanks for further transportation by truck or pipeline.

The natural gas supply for Regency's South Texas gathering systems is derived from a combination of natural gas wells located in a mature basin that generally have long lives and predictable gas flow rates and the NGLs-rich and oil-rich Eagle Ford shale formation, which lies directly under Regency's existing South Texas gathering system infrastructure.

Regency owns a 60% interest in Edwards Lime Gathering LLC, Talisman Energy USA Inc. and Statoil Texas Onshore Properties LP owns the remaining 40% interest. Regency operates a natural gas gathering oil pipeline and oil stabilization facilities for the joint venture while its joint venture partners operate a lean gas gathering system in the Edwards Lime natural gas trend that delivers to this system. In October 2013, an expansion of Edwards Lime Gathering LLC was completed to increase the system's capacity to 160 MMcf/d and provide for oil transportation and stabilization capacity of 17,000 Bbls/d.

Permian Region

- Approximately 6,597 miles of natural gas pipeline
- Seven processing and treating plants, a cryogenic natural gas processing plants, and a refrigeration plant

Regency's Permian Basin gathering system assets offer wellhead-to-market services to producers in the Texas counties of Ward, Winkler, Reeves and Pecos counties which surround the Waha Hub, one of Texas' developing NGLs-rich natural gas market areas. As a result of the proximity of Regency's system to the Waha Hub, the Waha gathering system has a variety of market outlets for the natural gas that we gather and process, including several major interstate and intrastate pipelines serving California, the mid-continent region of the United States and Texas natural gas markets. The NGL market outlets include Lone Star's NGL pipeline. Regency expanded its Permian Basin region through the SUGS acquisition, which increased their presence in the Permian Basin of Texas into Crocket, Upton, Crane, Ector, Culberson, Reagan and Andrews counties, as well as into the Eddy and Lea counties of New Mexico.

Regency offers producers up to four different levels of natural gas compression on the Permian Basin gathering systems, as compared to the two levels typically offered in the industry. By offering multiple levels of compression, Regency's gathering system is often more cost-effective for producers, since the producer is typically not required to pay for a level of compression that is higher than the level they require.

Regency's Permian region assets consist of a network of natural gas and NGL pipelines, seven processing plants and seven natural gas treating plants. These assets offer a broad array of services to producers including field gathering and compression of natural gas; treating, dehydration, sulfur recovery and reinjection and other conditioning; and natural gas processing and marketing of natural gas and NGLs.

In August 2013, Regency placed into service the $330 million expansion of Regency's Red Bluff processing plant, which increased capacity to 940 MMcf/d.

Regency also owns a 33.33% membership interest in Ranch JV which processes natural gas delivered from the NGLs-rich Bone Spring and Avalon shale formations in West Texas. The joint venture owns a 25 MMcf/d refrigeration plant and a 100 MMcf/d cryogenic processing plant.

Mid-Continent Region

- Approximately 3,493 miles of natural gas pipeline
- One processing plant

Regency's mid-continent systems are located in two large natural gas producing regions in the United States, the Hugoton Basin in southwest Kansas and the Anadarko Basin in western Oklahoma. These mature basins have continued to provide generally long-lived, predictable production volume. Regency's mid-continent gathering assets are extensive systems that gather, compress and dehydrate low-pressure gas from 1,500 wells. These systems are geographically concentrated, with each central facility located within 90 miles of the others. Regency operates its mid-continent gathering systems at low pressures to maximize the total throughput volumes from the connected wells. Wellhead pressures are therefore adequate to allow for flow of natural gas into the gathering lines without the cost of wellhead compression.

Regency also owns the Hugoton gathering system that has 1,900 miles of pipeline extending over nine counties in Kansas and Oklahoma. This system is operated by a third party.

Natural Gas Transportation Operations

RIGS has the capacity to transport up to 2.1 Bcf/d of natural gas. Results of RIGS's operations are determined primarily by the volumes of natural gas transported and subscribed on its intrastate pipeline system and the level of fees charged to customers or the margins received from purchases and sales of natural gas. RIGS generates revenues and margins principally under fee-based transportation contracts. The fixed capacity reservation charges related to RIGS that are not directly dependent on throughput volumes or commodity prices represent 93% of HPC's margin.

MEP pipeline system, operated by Kinder Morgan Energy Partners LP, has the capability to transport up to 1.8 Bcf/d of natural gas, and the pipeline capacity is fully subscribed with long-term binding commitments from creditworthy shippers. Results of MEP's operations are determined primarily by the volumes of natural gas transported and subscribed on its interstate pipeline system and the level of fees charged to customers. MEP generates revenues and margins principally under fee-based transportation contracts. The margin MEP earns is primarily related to fixed capacity reservation charges that are not directly dependent on throughput volumes or commodity prices. If a sustained decline in commodity prices should result in a decline in volumes, MEP's revenues would not be significantly impacted until expiration of the current contracts.

Gulf States is a small interstate pipeline that uses cost-based rates and terms and conditions of service for shippers wishing to secure capacity for interstate transportation service. Rates charged are largely governed by long-term negotiated rate agreements.

NGL Services Operations

Regency owns a 30% membership interest in Lone Star, which is a joint venture with ETP owning the remaining 70% membership interest. See "*NGL Transportation and Services*" under ETP's asset overview discussion for additional details.

Contract Services Operations

Regency's contract services operations can be divided into contract compression services and contract treating services. The natural gas contract compression services include designing, sourcing, owning, installing, operating, servicing, repairing and maintaining compressors and related equipment for which Regency guarantees their customers 98% mechanical availability for land installations and 96% mechanical availability for over-water installations. Regency focuses on meeting the complex requirements of field-wide compression applications, as opposed to targeting the compression needs of individual wells within a field. These field-wide applications include compression for natural gas gathering and natural gas processing. Regency believes that it improves the stability of its cash flow by focusing on field-wide compression applications because such applications generally involve long-term installations of multiple large horsepower compression units. Regency's contract compression operations are located in Texas, Oklahoma, Louisiana, Arkansas, Pennsylvania, New Mexico, Colorado and California.

Regency owns and operates a fleet of equipment used to provide treating services, such as carbon dioxide and hydrogen sulfide removal, natural gas cooling, dehydration and BTU management. Regency's contract treating services are primarily located in Texas, Louisiana and Arkansas.

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 operations 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 Products

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.

Retail Marketing

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 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

Credit risk refers to the risk that a counterparty may default on its contractual obligations resulting in a loss to the Partnership. Credit policies have been approved and implemented to govern the Partnership's portfolio of counterparties with the objective of mitigating credit losses. These policies establish guidelines, controls and limits to manage credit risk within approved tolerances by mandating an appropriate evaluation of the financial condition of existing and potential counterparties, monitoring agency credit ratings, and by implementing credit practices that limit exposure according to the risk profiles of the counterparties. Furthermore, the Partnership may at times require collateral under certain circumstances to mitigate credit risk as necessary. We also implement the use of industry standard commercial agreements which allow for the netting of positive and negative exposures associated with transactions executed under a single commercial agreement. Additionally, we utilize master netting agreements to offset credit exposure across multiple commercial agreements with a single counterparty or affiliated group of counterparties.

The Partnership's counterparties consist of a diverse portfolio of customers across the energy industry, including petrochemical companies, commercial and industrials, oil and gas producers, municipalities, utilities and midstream companies. Our overall exposure may be affected positively or negatively by macroeconomic or regulatory changes that could impact our counterparties to one extent or another. Currently, management does not anticipate a material adverse effect in our financial position or results of operations as a consequence of counterparty non-performance.

The natural gas transportation and midstream revenues are derived significantly from companies that engage in natural gas exploration and production activities. The discovery and development of new shale formations across the United States has created an abundance of natural gas resulting in a negative impact on prices in recent years. As a result, some of our exploration and production customers have been negatively impacted; however, we are monitoring these customers and mitigating credit risk as necessary.

During the year ended December 31, 2013, none of our individual customer 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 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.

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.

In 2011, in lieu of filing a new NGA Section 4 general rate case, Transwestern filed a proposed settlement with the FERC, which was approved by the FERC on October 31, 2011. In general, the settlement provides for the continued use of Transwestern's currently effective transportation and fuel tariff rates, with the exception of certain San Juan Lateral fuel rates, which we were required to reduce 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.

The rates charged for services on the Fayetteville Express pipeline are largely governed by long-term negotiated rate agreements. The FERC also approved cost-based recourse rates available to prospective shippers as an alternative to negotiated rates.

The rates charged for services on the Tiger pipeline are largely governed by long-term negotiated rate agreements.

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, the FERC determined that there was no reason at that time to expend the FERC's resources on a rate proceeding with respect to Trunkline LNG even though cost and revenue studies provided to the FERC indicated Trunkline LNG's revenues were in excess of its associated cost of service. 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.

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 CFTC also holds authority to monitor certain operations 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 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 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 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.

Our intrastate natural gas operations are also subject to regulation by various agencies in Texas, principally the 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.

Our NGL pipelines and operations may also be or become subject to state public utility or related jurisdiction which could impose additional safety and operational regulations relating to the design, siting, installation, testing, construction, operation, replacement and management of NGL gathering facilities.

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 operations 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 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, the courts and Congress. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements and complaint-based rate regulation.

In Texas, our gathering facilities are subject to regulation by the TRRC under the Texas Utilities Code in the same manner as described above for our intrastate pipeline facilities. Louisiana's Pipeline Operations Section of the Department of Natural Resources' Office of Conservation is generally responsible for regulating intrastate pipelines and gathering facilities in Louisiana and has authority to review and authorize natural gas transportation transactions and the construction, acquisition, abandonment and interconnection of physical facilities.

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

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

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

Regulation of Interstate Crude Oil and Refined Products Pipelines. Interstate common carrier pipeline operations are subject to rate regulation by the FERC under the Interstate Commerce Act ("ICA"), the Energy Policy Act of 1992, and related rules and orders. The ICA requires that tariff rates for petroleum pipelines be "just and reasonable" and not unduly discriminatory and that such rates and terms and conditions of service be filed with the FERC. This statute also permits interested persons to challenge proposed new or changed rates. The FERC is authorized to suspend the effectiveness of such rates for up to seven months, though rates are typically not suspended for the maximum allowable period. If the FERC finds that the new or changed rate is unlawful, it may require the carrier to pay refunds for the period that the rate was in effect. The 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 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, the 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 the 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 TRRC, the PA PUC, and the Oklahoma Corporation Commission. 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 DOT, under the PHMSA, pursuant to the Natural Gas Pipeline Safety Act of 1968, as amended ("NGPSA"), with respect to natural gas and the Hazardous Liquids Pipeline Safety Act of 1979, as amended ("HLPSA"), with respect to crude oil, NGLs and condensates. Both the NGPSA and the HLPSA were amended by the Pipeline Safety Improvement Act of 2002 ("PSI Act") and the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 ("PIPES Act"). The NGPSA and HLPSA, as amended, govern the design, installation, testing, construction, operation, replacement and management of natural gas as well as crude oil, NGL and condensate pipeline facilities. Pursuant to these acts, PHMSA has promulgated regulations governing pipeline wall thickness, design pressures, maximum operating pressures, pipeline patrols and leak surveys, minimum depth requirements, and emergency procedures, as well as other matters intended to ensure adequate protection for the public and to prevent accidents and failures. Additionally, PHMSA has established a series of rules requiring pipeline operators to develop and implement integrity management programs for gas transmission and hazardous liquid pipelines that, in the event of a pipeline leak or rupture, could affect high consequence areas ("HCAs"), which are areas where a release could have the most significant adverse consequences, including high population areas, certain drinking water sources and unusually sensitive ecological areas. Failure to comply with the safety laws and regulations may result in the imposition of administrative, civil and criminal remedies. The "rural gathering exemption" under the NGPSA presently exempts substantial portions of our gathering facilities from jurisdiction under the NGPSA, but does not apply to our intrastate natural gas pipelines. The portions of our facilities that are exempt include those portions located outside of cities, towns or any area designated as residential or commercial, such as a subdivision or shopping center. Changes to federal pipeline safety laws and regulations are being considered by Congress or PHMSA including changes to the "rural gathering exemption," which may be restricted in the future. While we believe our pipeline operations are in substantial compliance with applicable pipeline safety laws, safety laws and 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.

Most recently, these pipeline safety laws were amended on January 3, 2012 when President Obama signed into law the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 ("2011 Pipeline Safety Act") which 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 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.

In addition, states have adopted regulations, similar to existing PHMSA regulations, for intrastate gathering and transmission lines. The states in which we conduct operations typically have developed regulatory programs that parallel the federal regulatory scheme and are applicable to intrastate pipelines transporting natural gas and NGLs. Under such state regulatory programs, states have the authority to conduct pipeline inspections, to investigate accidents and to oversee compliance and enforcement, safety programs and record maintenance and reporting. Congress, PHMSA and individual states may pass or implement additional safety requirements that could result in increased compliance costs for us and other companies in our industry. For instance, notwithstanding the applicability of the OSHA's Process Safety Management ("PSM") regulations and the EPA's Risk Management Planning ("RMP") requirements at regulated facilities, PHMSA and one or more state regulators, including the TRRC, have in the recent past, expanded the scope of their regulatory inspections to include certain in-plant equipment and pipelines found within NGL fractionation facilities and associated storage facilities, in order to assess compliance of such equipment and pipelines with hazardous liquid pipeline safety requirements. These recent actions by PHMSA are currently subject to judicial and administrative challenges by one or more midstream operators; however, to the extent that such legal challenges are unsuccessful, midstream operators of NGL fractionation facilities and associated storage facilities subject to such inspection may be required to make operational changes or modifications at their facilities to meet standards beyond current PSM and RMP requirements, which changes or modifications may result in additional capital costs, possible operational delays and increased costs of operation that, in some instances, may be significant.

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 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 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 environmental laws and regulations or other unanticipated events will not arise in the future and give rise to 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 also generate both hazardous and nonhazardous wastes that are subject to requirements of the federal Resource Conservation and Recovery Act ("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 such as these examples 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 otherwise 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 releases 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.

As of December 31, 2013 and 2012, accruals of $403 million and $212 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 Partnership 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. Accruals for these environmental remediation activities amounted to $377 million at December 31, 2013, which is included in the total accruals above. These legacy sites that are subject to environmental assessments include formerly owned terminals and other logistics assets, retail sites that are no longer operated by Sunoco, closed and/or sold refineries and other formerly owned sites. In December 2013, a wholly-owned captive insurance company was established for these legacy sites. As of December 31, 2013 the captive insurance company held $348 million of cash, which was reported as restricted funds.

The Partnership'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 for known claims 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.

We have established a wholly-owned captive insurance company to bear certain risks associated with environmental obligations related to certain sites that are no longer operating. The premiums paid to the captive insurance company include estimates for environmental claims that have been incurred but not reported, based on an actuarially determined fully developed claims expense estimate. In such cases, we accrue losses attributable to unasserted claims based on the discounted estimates that are used to develop the premiums paid to the captive insurance company.

Under various environmental laws, including the RCRA (which relates to solid and hazardous waste treatment, storage and disposal), the Partnership has initiated corrective remedial action at its facilities, formerly owned facilities and third-party sites. At the Partnership's major manufacturing facilities, we have 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.

The Partnership 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. Our obligation 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. The 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, 2013, the aggregate of the estimated maximum additional reasonably possible losses, which relate to numerous individual sites, totaled approximately $6 million. This estimate of reasonably possible losses comprises estimates for remediation activities at current logistics and retail assets, and 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 the Partnership'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 the Partnership'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 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 Partnership'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 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 $7 million, which is included in the total environmental accruals mentioned above. Transwestern received FERC approval for rate recovery of projected soil and groundwater remediation costs not related to PCBs effective April 1, 2007. Transwestern, as part of ongoing arrangements with customers, continues to incur costs associated with containing and removing potential PCB contamination. Future costs cannot be reasonably estimated because remediation activities are undertaken as potential claims are made by customers and former customers. However, such future costs are not expected to have a material impact on our financial position, results of operations or cash flows.

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 considering, proposing or finalizing new rules and regulations that could impact our existing operations and the costs and timing of new infrastructure development. For example, 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 operations 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.

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 were required to comply by October 19, 2013. Many of our facilities, including our leased compressors have been impacted by these new rules. We have incurred increased costs to bring engines into compliance with the new emission requirements, but such costs were not material.

Clean Water Act. The Federal Water Pollution Control Act of 1972, also known as 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 National Pollutant Discharge Elimination System, 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 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 Clean Water Act and comparable state laws can impose substantial administrative, civil and criminal penalties for non-compliance including spills and other non-authorized discharges. 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. Similar protection is offered to migratory birds under the Migratory Bird Treaty Act. We may operate in areas that are currently designated as a habitat for endangered or threatened species or where the discovery of previously unidentified endangered species, or the designation of additional species as endangered or threatened may occur in which event such one or more developments 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. Based on these findings, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that, among other things, would restrict emissions of greenhouse gases from motor vehicles as well as established Prevention of Significant Deterioration (“PSD”) and Title V permitting reviews for certain large stationary sources that are potential sources of greenhouse gas emissions. 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 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, the EPA has 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, including onshore oil and natural gas production, processing, transmission, storage and distribution facilities. We are monitoring greenhouse gas emissions from certain of our operations in accordance with the greenhouse gas emissions reporting rule and believe that our monitoring and reporting activities are in substantial compliance with applicable reporting obligations.

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. Numerous 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 by reducing demand for oil, natural gas and NGLs.

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.

Employees

As of January 31, 2014, ETE and its consolidated subsidiaries employed an aggregate of 13,573 employees, 1,466 of which are represented by labor unions. We and our subsidiaries 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.

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. ETP, Regency, Panhandle and Sunoco Logistics file Annual Reports on Form 10-K that include risk factors that can be reviewed for further information. The risk factors set forth below, and those included in ETP's, Regency's, Panhandle'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 or other external factors.

The source of our earnings and cash flow is cash distributions from ETP and Regency. Therefore, the amount of distributions we are currently able to make to our Unitholders may fluctuate based on the level of distributions ETP and Regency makes to their partners. ETP or Regency may not be able to continue to make quarterly distributions at their current level or increase their quarterly distributions in the future. In addition, while we would expect to increase or decrease distributions to our Unitholders if ETP or Regency increases or decreases distributions to us, the timing and amount of such increased or decreased distributions, if any, will not necessarily be comparable to the timing and amount of the increase or decrease in distributions made by ETP or Regency to us.

Our ability to distribute cash received from ETP and Regency to our Unitholders is limited by a number of factors, including:

- interest expense and principal payments on our indebtedness;
- restrictions on distributions contained in any current or future debt agreements;
- our general and administrative expenses;
- expenses of our subsidiaries other than ETP or Regency, including tax liabilities of our corporate subsidiaries, if any;
- capital contributions we may make to maintain our General Partner interests in ETP or Regency upon the issuance of additional partnership securities by ETP or Regency, as applicable; and
- reserves our General Partner believes prudent for us to maintain for the proper conduct of our business or to provide for future distributions.

We cannot guarantee that in the future we will be able to pay distributions or that any distributions we do make will be at or above our current quarterly distribution. The actual amount of cash that is available for distribution to our Unitholders will depend on numerous factors, many of which are beyond our control or the control of our General Partner.

Our only significant assets are our partnership interests, including the incentive distribution rights, in ETP and Regency and, therefore, our cash flow is dependent upon the ability of ETP and Regency to make distributions in respect of those partnership interests.

We do not have any significant assets other than our partnership interests in ETP and Regency. As a result, our cash flow depends on the performance of ETP, Regency and their respective subsidiaries and ETP's and Regency's ability to make cash distributions to us, which is dependent on the results of operations, cash flows and financial condition of ETP and Regency.

The amount of cash that ETP and Regency can distribute to their partners, including us, each quarter depends upon the amount of cash they generate from their operations, which will fluctuate from quarter to quarter and will depend upon, among other things:

- the amount of natural gas, crude oil and refined products transported through ETP's and Regency's transportation pipelines and gathering systems;
- the level of throughput in processing and treating operations;
- the fees charged and the margins realized by ETP and Regency for their 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 ETP receives with respect to the Regency and AmeriGas common units that ETP or their subsidiaries own;
- the weather in their respective operating areas;
- the level of competition from other midstream, transportation and storage and retail marketing companies and other energy providers;
- the level of their respective operating costs;
- prevailing economic conditions; and
- the level and results of their respective derivative activities.

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

- the level of capital expenditures they 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;
- debt service requirements;
- fluctuations in working capital needs;
- their ability to borrow under their respective revolving credit facilities;
- their ability to access capital markets;
- restrictions on distributions contained in their respective debt agreements; and
- the amount, if any, of cash reserves established by the board of directors and their respective general partners in their discretion for the proper conduct of their respective businesses.

ETE does not have any control over many of these factors, including the level of cash reserves established by the board of directors and ETP's and Regency's respective General Partners. Accordingly, we cannot guarantee that ETP or Regency will have sufficient available cash to pay a specific level of cash distributions to its partners.

Furthermore, Unitholders should be aware that the amount of cash that ETP and Regency have available for distribution depends primarily upon cash flow and is not solely a function of profitability, which is affected by non-cash items. As a result, ETP and Regency may declare and/or pay cash distributions during periods when they record net losses. Please read "Risks Related to the Businesses of Energy Transfer Partners and Regency Energy Partners" included in this Item 1A for a discussion of further risks affecting ETP's and Regency's ability to generate distributable cash flow.

We may issue an unlimited number of limited partner interests without the consent of our Unitholders, which will dilute Unitholders' ownership interest in us and may increase the risk that we will not have sufficient available cash to maintain or increase our per unit distribution level.

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 by us will have the following effects:

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

In addition, ETP and Regency may sell an unlimited number of limited partner interests without the consent of the respective Unitholders, which will dilute existing interests of the respective Unitholders, including us. The issuance of additional Common Units or other equity securities by ETP will have essentially the same effects as detailed above.

ETP or Regency may issue additional Common Units, which may increase the risk that ETP or Regency will not have sufficient available cash to maintain or increase its per unit distribution level.

The partnership agreements of each ETP and Regency allow ETP and Regency, respectively, to issue an unlimited number of additional limited partner interests. The issuance of additional common units or other equity securities by ETP or Regency will have the following effects:

- Unitholders' current proportionate ownership interest in ETP or Regency, as applicable, will decrease;
- the amount of cash available for distribution on each common unit or partnership security may decrease;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding common unit may be diminished; and
- the market price of ETP's or Regency's Common Units, as applicable, may decline.

The payment of distributions on any additional units issued by ETP or Regency may increase the risk that ETP or Regency, as applicable, may not have sufficient cash available to maintain or increase its per unit distribution level, which in turn may impact the available cash that we have to meet our obligations.

Sunoco Logistics may issue additional common units, which may increase the risk that Sunoco Logistics will not have sufficient available cash to maintain or increase its per unit distribution level.

Sunoco Logistics' partnership agreement allows it to issue an unlimited number of additional limited partner interests. The issuance of additional common units or other equity securities by Sunoco Logistics will have the following effects:

- Unitholders' current proportionate ownership interest in Sunoco Logistics, as applicable, will decrease;
- the amount of cash available for distribution on each common unit or partnership security may decrease;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding common unit may be diminished; and
- the market price of Sunoco Logistics common units may decline.

The payment of distributions on any additional units issued by Sunoco Logistics may increase the risk that Sunoco Logistics may not have sufficient cash available to maintain or increase its per unit distribution level, which in turn may impact the available cash that we have to meet our obligations.

Unitholders have limited voting rights and are not entitled to elect the General Partner or its directors. In addition, even if Unitholders are dissatisfied, they cannot easily remove the General Partner.

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 or the officers or directors of our General Partner on an annual or other continuing basis.

Furthermore, if our Unitholders are dissatisfied with the performance of our General Partner, they may be unable to remove our General Partner. Our General Partner may not be removed except upon the vote of the holders of at least 66 $^{2}/_{3}$% of our outstanding units. As of February 21, 2014, our directors and executive officers directly or indirectly own approximately 19% of our outstanding Common Units. It will be particularly difficult for our General Partner to be removed without the consent of our directors and executive officers. As a result, the price at which our Common Units will trade may be lower because of the absence or reduction of a takeover premium in the trading price.

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 members of our General Partner may transfer all or part of their ownership interest in our General Partner to a third party without the consent of the Unitholders. Any new owner or owners of our General Partner or the general partner of the General Partner would be in a position to replace the directors and officers of our General Partner with its own choices and to control the decisions made and actions taken by the board of directors and officers.

We are dependent on third parties, including key personnel of ETP under a shared services agreement, to provide the financial, accounting, administrative and legal services necessary to operate our business.

We rely on the services of key personnel of ETP, including the ongoing involvement and continued leadership of Kelcy L. Warren, one of the founders of ETP's midstream business, as well as other key members of ETP's management team such as Marshall S. (Mackie) McCrea, III, President and Chief Operating Officer. Mr. Warren and Mr. McCrea have been integral to the success of ETP's midstream and intrastate transportation and storage businesses because of their ability to identify and develop strategic business opportunities. Losing the leadership of either Mr. Warren or Mr. McCrea could make it difficult for ETP to identify internal growth projects and accretive acquisitions, which could have a material adverse effect on ETP's ability to increase the cash distributions paid on its partnership interests.

ETP's executive officers that provide services to us pursuant to a shared services agreement allocate their time between us and ETP. To the extent that these officers face conflicts regarding the allocation of their time, we may not receive the level of attention from them that the management of our business requires. If ETP is unable to provide us with a sufficient number of personnel with the appropriate level of technical accounting and financial expertise, our internal accounting controls could be adversely impacted.

Cost reimbursements due to our General Partner may be substantial and may reduce our ability to pay the distributions to our 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 our General Partner. The reimbursement of these expenses and the payment of these fees could adversely affect our ability to make distributions to our Unitholders. Our General Partner has sole discretion to determine the amount of these expenses and fees.

In addition, under Delaware partnership law, our General Partner has unlimited liability for our obligations, such as our debts and environmental liabilities, except for our contractual obligations that are expressly made without recourse to our General Partner. To the extent our General Partner incurs obligations on our behalf, we are obligated to reimburse or indemnify it. If we are unable or unwilling to reimburse or indemnify our General Partner, our General Partner may take actions to cause us to make payments of these obligations and liabilities. Any such payments could reduce the amount of cash available for distribution to our Unitholders and cause the value of our Common Units to decline.

A reduction in ETP's or Regency's distributions will disproportionately affect the amount of cash distributions to which we are entitled.

Through our ownership of equity interests in ETP GP, the holder of the incentive distribution rights in ETP, we are entitled to receive our pro rata share of specified percentages of total cash distributions made by ETP as it reaches established target cash distribution levels as specified in the ETP partnership agreement. We currently receive our pro rata share of cash distributions from ETP based on the highest incremental percentage, 48%, to which ETP GP is entitled pursuant to its incentive distribution rights in ETP. A decrease in the amount of distributions by ETP to less than $0.4125 per Common Unit per quarter would reduce ETP GP's percentage of the incremental cash distributions above $0.3175 per Common Unit per quarter from 48% to 23%. As a result, any such reduction in quarterly cash distributions from ETP would have the effect of disproportionately reducing the amount of all distributions that we receive from ETP based on our ownership interest in the incentive distribution rights in ETP as compared to cash distributions we receive from ETP on our General Partner interest in ETP and our ETP Common Units.

Similarly, we currently receive a pro rata share of incremental cash distributions from Regency at the 23% level pursuant to Regency GP's incentive distribution rights in Regency as specified in the Regency partnership agreement. A decrease in the amount of distributions by Regency to less than $0.4375 per Common Unit per quarter would have reduced Regency GP's percentage of the incremental cash distributions above $0.4025 per Common Unit per quarter from 23% to 13%. As a result, any such reduction in quarterly cash distributions from Regency would have the effect of disproportionately reducing the amount of all distributions that we receive from Regency based on our ownership interest in the incentive distribution rights of Regency as compared to cash distributions we receive from Regency on our General Partner interest in Regency and our Regency Common Units.

A reduction in Sunoco Logistics' distributions will disproportionately affect the amount of cash distributions to which we are entitled.

Through our ownership of equity interests in Sunoco Partners, the holder of the incentive distribution rights in Sunoco Logistics, we are entitled to receive our pro rata share of specified percentages of total cash distributions made by Sunoco Logistics as it reaches established target cash distribution levels as specified in the Sunoco Logistics partnership agreement. We currently receive our pro rata share of cash distributions from Sunoco Logistics based on the highest incremental percentage, 48%, to which Sunoco Partners is entitled pursuant to its incentive distribution rights in Sunoco Logistics. A decrease in the amount of distributions by Sunoco Logistics to less than $0.5275 per common unit per quarter would reduce Sunoco Partners' percentage of the incremental cash distributions above $0.1917 per common unit per quarter from 48% to 35%. As a result, any such reduction in quarterly cash distributions from Sunoco Logistics would have the effect of disproportionately reducing the amount of all distributions that we receive from Sunoco Logistics based on our ownership interest in the incentive distribution rights in Sunoco Logistics as compared to cash distributions we receive from Sunoco Logistics on our General Partner interest in Sunoco Logistics and our Sunoco Logistics common units.

The consolidated debt level and debt agreements of ETP and Regency and those of their subsidiaries may limit the distributions we receive from ETP and Regency, as well as our future financial and operating flexibility.

ETP's and Regency's levels of indebtedness affect their operations in several ways, including, among other things:

- a significant portion of ETP's, Regency's and their subsidiaries' cash flows 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 to us;
- covenants contained in ETP's, Regency's and their subsidiaries' existing debt agreements require ETP, Regency and their subsidiaries, as applicable, to meet financial tests that may adversely affect their flexibility in planning for and reacting to changes in their respective businesses;
- ETP's, Regency's and their 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;
- ETP and Regency may be at a competitive disadvantage relative to similar companies that have less debt;
- ETP and Regency may be more vulnerable to adverse economic and industry conditions as a result of their significant debt levels; and
- failure by ETP, Regency or their subsidiaries to comply with the various restrictive covenants of the respective debt agreements could negatively impact ETP's and Regency's ability to incur additional debt, including their ability to utilize the available capacity under their revolving credit facilities, and to pay distributions.

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.

A downgrade of our credit rating could impact our liquidity, access to capital and our costs of doing business, and maintaining credit ratings is under the control of independent third parties.

A downgrade of our credit rating might increase our cost of borrowing and could require us to post collateral with third parties, negatively impacting our available liquidity. Our ability to access capital markets could also be limited by a downgrade of our credit rating and other disruptions. Such disruptions could include:

- economic downturns;

- deteriorating capital market conditions;
- declining market prices for natural gas, NGLs and other commodities;
- terrorist attacks or threatened attacks on our facilities or those of other energy companies; and
- the overall health of the energy industry, including the bankruptcy or insolvency of other companies.

Credit rating agencies perform independent analysis when assigning credit ratings. The analysis includes a number of criteria including, but not limited to, business composition, market and operational risks, as well as various financial tests. Credit rating agencies continue to review the criteria for industry sectors and various debt ratings and may make changes to those criteria from time to time. Credit ratings are not recommendations to buy, sell or hold investments in the rated entity. Ratings are subject to revision or withdrawal at any time by the rating agencies, and we cannot assure you that we will maintain our current credit ratings.

ETP and Regency are not prohibited from competing with us.

Neither our partnership agreement nor the partnership agreements of ETP or Regency prohibit ETP or Regency from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, ETP and/or Regency may acquire, construct or dispose of any assets in the future without any obligation to offer us the opportunity to purchase or construct any of those assets.

Sunoco Logistics is not prohibited from competing with us.

Neither our partnership agreement nor the partnership agreements of Sunoco Logistics prohibits Sunoco Logistics from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, Sunoco Logistics may acquire, construct or dispose of any assets in the future without any obligation to offer us the opportunity to purchase or construct any of those assets.

Capital projects will require significant amounts of debt and equity financing which may not be available to ETP or Regency on acceptable terms, or at all.

ETP and Regency plan to fund their growth capital expenditures, including any new future pipeline construction projects and improvements or repairs to existing facilities that ETP or Regency may undertake, with proceeds from sales of ETP's or Regency's debt and equity securities and borrowings under their respective revolving credit facilities; however, ETP or Regency cannot be certain that they will be able to issue debt and equity securities on terms satisfactory to them, or at all. In addition, ETP or Regency may be unable to obtain adequate funding under their current revolving credit facility because ETP's or Regency's lending counterparties may be unwilling or unable to meet their funding obligations. If ETP or Regency are unable to finance their expansion projects as expected, ETP or Regency could be required to seek alternative financing, the terms of which may not be attractive to ETP or Regency, or to revise or cancel its expansion plans.

A significant increase in ETP's or Regency's indebtedness that is proportionately greater than ETP's or Regency's respective issuances of equity could negatively impact ETP's or Regency's respective credit ratings or their ability to remain in compliance with the financial covenants under their respective revolving credit agreements, which could have a material adverse effect on ETP's or Regency's financial condition, results of operations and cash flows.

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

In addition to our exposure to commodity prices, we have significant exposure to changes in interest rates. Approximately $2.63 billion of our consolidated debt as of December 31, 2013 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 or indirect owners 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 indirect owners 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 us to service their indebtedness.

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

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.

Unitholders may not have limited liability if a court finds that unitholder actions constitute control of our business.

Under Delaware law, a unitholder could be held liable for our obligations to the same extent as a general partner if a court determined that the right of unitholders to remove our general partner or to take other action under our partnership agreement constituted participation in the “control” of our business.

Our general partner generally has unlimited liability for our obligations, such as our debts and environmental liabilities, except for those contractual obligations that are expressly made without recourse to our general partner. Our partnership agreement allows the general partner to incur obligations on our behalf that are expressly non-recourse to the general partner. The general partner has entered into such limited recourse obligations in most instances involving payment liability and intends to do so in the future.

In addition, Section 17-607 of the Delaware Revised Uniform Limited Partnership Act provides that under some circumstances, a unitholder may be liable to us for the amount of a distribution for a period of three years from the date of the distribution.

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, 2013, we had approximately $23.20 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.

Unitholders may be required to sell their units to our general partner at an undesirable time or price.

If at any time less than 10% 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.

A downgrade of our credit rating could impact our liquidity, access to capital and our costs of doing business, and maintaining credit ratings is under the control of independent third parties.

A downgrade of our credit rating might increase our cost of borrowing and could require us to post collateral with third parties, negatively impacting our available liquidity. Our ability to access capital markets could also be limited by a downgrade of our credit rating and other disruptions. Such disruptions could include:

- economic downturns;
- deteriorating capital market conditions;
- declining market prices for natural gas, NGLs and other commodities;
- terrorist attacks or threatened attacks on our facilities or those of other energy companies; and
- the overall health of the energy industry, including the bankruptcy or insolvency of other companies.

Credit rating agencies perform independent analysis when assigning credit ratings. The analysis includes a number of criteria including, but not limited to, business composition, market and operational risks, as well as various financial tests. Credit rating agencies continue to review the criteria for industry sectors and various debt ratings and may make changes to those criteria from time to time. Credit ratings are not recommendations to buy, sell or hold investments in the rated entity. Ratings are subject to revision or withdrawal at any time by the rating agencies, and we cannot assure you that we will maintain our current credit ratings.

Risks Related to Conflicts of Interest

Although we control ETP and Regency through our ownership of their respective General Partners, ETP's General Partner owes fiduciary duties to ETP and ETP's Unitholders, and Regency's General Partner owes fiduciary duties to Regency and Regency's Unitholders, which may conflict with our interests.

Conflicts of interest exist and may arise in the future as a result of the relationships between us and our affiliates, on the one hand, and ETP, Regency and their respective limited partners, on the other hand. The directors and officers of ETP's and Regency's General Partners have fiduciary duties to manage ETP and Regency, respectively, in a manner beneficial to us. At the same time, the General Partners have fiduciary duties to manage ETP and Regency, respectively, in a manner beneficial to ETP, Regency and their respective limited partners. The board of directors of ETP's General Partner or Regency's general partner will resolve any such conflict and have broad latitude to consider the interests of all parties to the conflict. The resolution of these conflicts may not always be in our best interest.

For example, conflicts of interest with ETP or Regency may arise in the following situations:

- the allocation of shared overhead expenses to ETP, Regency and us;
- the interpretation and enforcement of contractual obligations between us and our affiliates, on the one hand, and ETP or Regency, on the other hand;
- the determination of the amount of cash to be distributed to ETP's or Regency's partners and the amount of cash to be reserved for the future conduct of ETP's or Regency's business;
- the determination whether to make borrowings under ETP's or Regency's respective revolving credit facility to pay distributions to ETP's or Regency's partners, as applicable;
- the determination of whether a business opportunity (such as a commercial development opportunity or an acquisition) that we may become aware of independently of ETP or Regency is made available for either ETP or Regency, or both, to pursue; and
- any decision we make in the future to engage in business activities independent of ETP or Regency.

The fiduciary duties of our General Partner's officers and directors may conflict with those of ETP's or Regency's respective General Partners.

Conflicts of interest may arise because of the relationships among ETP, Regency, their General Partners and us. Our General Partner's directors and officers have fiduciary duties to manage our business in a manner beneficial to us and our Unitholders. Some of our General Partner's directors are also directors and officers of ETP's General Partner or Regency's General Partner, and have fiduciary duties to manage the respective businesses of ETP and Regency in a manner beneficial to ETP, Regency and their respective Unitholders. The resolution of these conflicts may not always be in our best interest or that of our Unitholders.

Potential conflicts of interest may arise among our General Partner, its affiliates and us. Our General Partner and its affiliates have limited fiduciary duties to us, which may permit them to favor their own interests to the detriment of us.

Conflicts of interest may arise among our General Partner and its affiliates, on the one hand, and us, on the other hand. As a result of these conflicts, our General Partner may favor its own interests and the interests of its affiliates over our interests. These conflicts include, among others, the following:

- Our General Partner is allowed to take into account the interests of parties other than us, including ETP, Regency and their respective affiliates and any General Partners and limited partnerships acquired in the future, in resolving conflicts of interest, which has the effect of limiting its fiduciary duties to us.
- Our General Partner has limited its liability and reduced its fiduciary duties under the terms of our partnership agreement, while also restricting the remedies available for actions that, without these limitations, might constitute breaches of fiduciary duty. As a result of purchasing our units, Unitholders consent to various actions and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable state law.
- Our General Partner determines the amount and timing of our investment transactions, borrowings, issuances of additional partnership securities and reserves, each of which can affect the amount of cash that is available for distribution.
- Our General Partner determines which costs it and its affiliates have incurred are reimbursable by us.
- Our partnership agreement does not restrict our General Partner from causing us to pay it or its affiliates for any services rendered, or from entering into additional contractual arrangements with any of these entities on our behalf, so long as the terms of any such payments or additional contractual arrangements are fair and reasonable to us.
- Our General Partner controls the enforcement of obligations owed to us by it and its affiliates.
- Our General Partner decides whether to retain separate counsel, accountants or others to perform services for us.

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

Our partnership agreement contains provisions that reduce the standards to which our General Partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement:

- permits our General Partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our General Partner. 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 "good faith" if it reasonably believes that the decisions are in our best interests;
- generally provides that affiliated transactions and resolutions of conflicts of interest not approved by the Audit and Conflicts Committee of the board of directors of our General Partner and not involving a vote of Unitholders must be on terms no less favorable to us than those generally being provided to or available from unrelated third parties or 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 totality of the relationships among the parties involved, including other transactions that may be particularly advantageous or beneficial to us; 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 any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that the General Partner or those other persons acted in bad faith or engaged in fraud, willful misconduct or gross negligence.

Our General Partner has a limited call right that may require Unitholders to sell their units at an undesirable time or price.

If at any time our General Partner and its affiliates own more than 90% of our outstanding units, our General Partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the units held by unaffiliated persons at a price not less than their then-current market price. As a result, Unitholders may be required to sell their units at an undesirable time or price and may not receive any return on their investment. Unitholders may also incur a tax liability upon a sale of their units. As of December 31, 2013, the directors and executive officers of our General Partner owned approximately 19% of our Common Units.

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.

Risks Related to the Businesses of ETP and Regency

Since our cash flows consist exclusively of distributions from ETP and Regency, risks to the businesses of ETP and Regency are also risks to us. We have set forth below risks to the businesses of ETP and Regency, the occurrence of which could have a negative impact on their respective financial performance and decrease the amount of cash they are able to distribute to us.

ETP and Regency do not control, and therefore may not be able to cause or prevent certain actions by, certain of their joint ventures.

Certain of ETP's and Regency's joint ventures have their own governing boards, and ETP or Regency may not control all of the decisions of those boards. Consequently, it may be difficult or impossible for ETP or Regency to cause the joint venture entity to take actions that ETP or Regency believe would be in their or the joint venture's best interests. Likewise, ETP or Regency may be unable to prevent actions of the joint venture.

ETP and Regency are exposed to the credit risk of their respective customers, and an increase in the nonpayment and nonperformance by their respective customers could reduce their respective ability to make distributions to their Unitholders, including to us.

The risks of nonpayment and nonperformance by ETP's and Regency's respective customers are a major concern in their respective businesses. 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. ETP and Regency are subject to risks of loss resulting from nonpayment or nonperformance by their respective 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 ETP's and Regency's customers. Any substantial increase in the nonpayment and nonperformance by ETP's or Regency's customers could have a material adverse effect on ETP's or Regency's respective results of operations and operating cash flows.

Income from ETP's 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;
- 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.

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

A material decrease in demand or distribution of crude oil available for transport through Sunoco Logistics' pipelines or terminal facilities could materially and adversely affect our results of operations, financial position, or cash flows.

The volume of crude oil transported through Sunoco Logistics' crude oil pipelines and terminal facilities depends on the availability of attractively priced crude oil produced or received in the areas serviced by its assets. A period of sustained crude oil price declines could lead to a decline in drilling activity, production and import levels in these areas. Similarly, a period of sustained increases in the price of crude oil supplied from any of these areas, as compared to alternative sources of crude oil available to Sunoco Logistics' customers, could materially reduce demand for crude oil in these areas. In either case, the volumes of crude oil transported in Sunoco Logistics' crude oil pipelines and terminal facilities could decline, and it could likely be difficult to secure alternative sources of attractively priced crude oil supply in a timely fashion or at all. If Sunoco Logistics is unable to replace any significant volume declines with additional volumes from other sources, our results of operations, financial position, or cash flows could be materially and adversely affected.

ETP and Regency are affected by competition from other midstream, transportation and storage and retail marketing companies.

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

ETP's and Regency's 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.

ETP's crude oil and refined products pipeline operations face significant competition from other pipelines for large volume shipments. These operations also face competition from trucks for incremental and marginal volumes in areas served by Sunoco Logistics' pipelines. Further, our 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.

ETP also faces strong competition in the market for the sale of retail gasoline and merchandise. ETP's 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 retail marketing competitors, including the impact of foreign 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.

ETP and Regency 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 revenues and limit future profitability.

The retention or replacement of existing customers and the volume of services that ETP and Regency 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.

A significant portion of ETP and Regency’s 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.

ETP and Regency also receive a substantial portion of revenues by providing natural gas gathering, processing, treating, transportation and storage services. While a substantial portion of their services are sold under long-term contracts for reserved service, they 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 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 ETP and Regency’s 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. ETP and Regency receive substantially all of their transportation revenues through dedicated contracts under which the customer agrees to deliver the total output from particular processing plants that are connected only to their 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, ETP’s refined products storage revenues are primarily derived from fixed capacity arrangements between us and our customers, a portion of its revenue is derived from fungible storage and throughput arrangements, under which ETP’s revenue is more dependent upon demand for storage from its customers.

The volume of crude oil and refined products transported through ETP’s 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 ETP and Regency’s midstream, transportation, terminalling and storage facilities or a reduction in the volume of the services customers purchase from them, or their inability to attract new customers and service volumes would negatively affect revenues, be detrimental to growth, and adversely affect results of operations.

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

In order to maintain or increase throughput levels on ETP’s gathering systems and transportation pipeline systems and asset utilization rates at our treating and processing plants, ETP must continually contract for new natural gas supplies and natural gas transportation services.

A substantial portion of ETP’s assets, including its gathering systems and processing and treating plants, are connected to natural gas reserves and wells that experience declining production over time. ETP’s 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. ETP may not be able to obtain additional contracts for natural gas supplies for its natural gas gathering systems, and may be unable to maintain or increase the levels of natural gas throughput on its 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 its transportation pipelines or markets to which ETP’s systems connect. ETP has no control over the level of drilling activity in its areas of operation, the amount of reserves underlying the wells and the rate at which production from a well will decline. In addition, ETP has no control over producers or their production and contracting decisions.

While a substantial portion of ETP’s services are provided under long-term contracts for reserved service, it also provides service on an unreserved basis. The reserves available through the supply basins connected to our gathering, processing, treating, transportation and storage facilities may decline and may not be replaced by other sources of supply. A decrease in development or production activity could cause a decrease in the volume of unreserved services ETP provides and a decrease in the number and volume of its contracts for reserved transportation service over the long run, which in each case would adversely affect 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.

ETP is entirely dependent upon third parties for the supply of refined products such as gasoline and diesel for its retail marketing business.

ETP is required to purchase refined products from third party sources, including the joint venture that acquired Sunoco’s Philadelphia refinery. ETP may also need to contract for new ships, barges, pipelines or terminals which it has not historically used to transport these products to its markets. The inability to acquire refined products and any required transportation services at favorable prices may adversely affect ETP’s business and results of operations.

The profitability of certain activities in ETP’s and Regency’s 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 on ETP’s and Regency’s systems, they purchase natural gas from producers at the wellhead and then gather and deliver the natural gas to pipelines where they typically resell the natural gas under various arrangements, including sales at index prices. Generally, the gross margins they realize under these arrangements decrease in periods of low natural gas prices.

ETP and Regency 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, ETP and Regency 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, ETP and Regency deliver an agreed upon percentage of the residue gas and NGL volumes to the producer and sell the volumes ETP and Regency keep to third parties at market prices. Under these arrangements, 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 ETP’s and Regency’s revenues and results of operations.

Under keep-whole arrangements, ETP and Regency generally sell the NGLs produced from our gathering and processing operations at market prices. Because the extraction of the NGLs from the natural gas during processing reduces the Btu content of the natural gas, ETP and Regency 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, gross margins generally decrease when the price of natural gas increases relative to the price of NGLs.

When ETP and Regency process the gas for a fee under processing fee agreements, they may guarantee recoveries to the producer. If recoveries are less than those guaranteed to the producer, ETP or Regency may suffer a loss by having to supply liquids or its cash equivalent to keep the producer whole.

ETP and Regency also receive fees and retain gas in kind from our natural gas transportation and storage customers. ETP and Regency’s fuel retention fees and the value of gas that they retain in kind are directly affected by changes in natural gas prices. Decreases in natural gas prices tend to decrease fuel retention fees and the value of retained gas.

In addition, ETP receives revenue from its 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 ETP’s off-gas processing and fractionation services and could have an adverse effect on ETP’s results of operations.

The use of derivative financial instruments could result in material financial losses by ETP and Regency.

From time to time, ETP and Regency 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 their trading, marketing and/or system optimization activities. To the extent that either ETP or Regency hedges its commodity price and interest rate exposures, it foregoes the benefits it would otherwise experience if commodity prices or interest rates were to change favorably. In addition, even though monitored by management, ETP's and Regency's 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 ETP's or Regency's physical or financial positions, or internal hedging policies and procedures are not followed.

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.

ETP's and Regency's natural gas and NGL revenues depend on their customers' ability to use ETP's and Regency's pipelines and third-party pipelines over which we have no control.

ETP's and Regency's natural gas transportation, storage and NGL businesses depend, in part, on their customers' ability to obtain access to pipelines to deliver gas to and receive gas from ETP and Regency. 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 ETP's and Regency's ability, and the ability of their customers, to transport natural gas to and from their pipelines and facilities and a corresponding material adverse effect on their transportation and storage revenues. In addition, the rates charged by interconnected pipelines for transportation to and from ETP's and Regency's facilities affect the utilization and value of their 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 storage revenues.

Shippers using ETP's and Regency's oil pipelines and terminals are also dependent upon their 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 ETP's and Regency's pipelines or through their terminals. Similarly, if additional shippers begin transporting volume over interconnecting oil pipelines, the allocations of pipeline capacity to ETP and Regency's existing shippers on these interconnecting pipelines could be reduced, which also could reduce volumes transported in their pipelines or through their 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 ETP and Regency's results of operations, financial position, or cash flows.

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

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

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. In either case, 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.

ETP and Regency may not be able to fully execute their growth strategies if they encounter increased competition for qualified assets.

ETP and Regency each have strategies that contemplate growth through the development and acquisition of a wide range of midstream and other energy infrastructure assets while maintaining strong balance sheets. These strategies include constructing and acquiring additional assets and businesses to enhance their ability to compete effectively and diversify their respective asset portfolios, thereby providing more stable cash flow. ETP and Regency regularly consider and enter into discussions regarding the acquisition of additional assets and businesses, stand-alone development projects or other transactions that ETP and Regency believe will present opportunities to realize synergies and increase cash flow.

Consistent with their strategies, managements of ETP and Regency 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 ETP or Regency management's participation in processes that involve a number of potential buyers, commonly referred to as "auction" processes, as well as situations in which ETP or Regency believes it is the only party or one of a very limited number of potential buyers in negotiations with the potential seller. We cannot assure that ETP's or Regency's acquisition efforts will be successful or that any acquisition will be completed on favorable terms.

In addition, ETP and Regency each are experiencing increased competition for the assets they purchase or contemplate purchasing. Increased competition for a limited pool of assets could result in ETP or Regency losing to other bidders more often or acquiring assets at higher prices, both of which would limit ETP's or Regency's ability to fully execute their respective growth strategies. Inability to execute their respective growth strategies may materially adversely impact ETP's or Regency's results of operations.

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

As of December 31, 2013, our consolidated balance sheets reflected $5.89 billion of goodwill and $2.26 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.

During the fourth quarter of 2013, we recorded a goodwill impairment charge of $689 million on our Trunkline LNG reporting unit. See Note 2 to our consolidated financial statements for additional information.

If ETP and Regency do not make acquisitions on economically acceptable terms, their future growth could be limited.

ETP's and Regency's results of operations and their ability to grow and to increase distributions to Unitholders will depend in part on their ability to make acquisitions that are accretive to their respective distributable cash flow.

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

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

Furthermore, even if ETP or Regency consummates acquisitions that it believes will be accretive, those acquisitions may in fact adversely affect its results of operations or result in a decrease in distributable cash flow per unit. Any acquisition involves potential risks, including the risk that ETP or Regency may:

- fail to realize anticipated benefits, such as new customer relationships, cost-savings or cash flow enhancements;
- decrease its liquidity by using a significant portion of its available cash or borrowing capacity to finance acquisitions;
- significantly increase its interest expense or financial leverage if the acquisition is financed with additional debt;

- 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 there is no indemnity or the indemnity is inadequate;
- be unable to hire, train or retrain qualified personnel to manage and operate its growing business and assets;
- less effectively manage its historical assets, due to the diversion of management's attention from other business concerns; or
- incur other significant charges, such as impairment of goodwill or other intangible assets, asset devaluation or restructuring charges.

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

If ETP and Regency do not continue to construct new pipelines, their future growth could be limited.

ETP's and Regency's results of operations and their ability to grow and to increase distributable cash flow per unit will depend, in part, on their ability to construct pipelines that are accretive to their respective distributable cash flow. ETP or Regency may be unable to construct pipelines that are accretive to distributable cash flow for any of the following reasons, among others:

- inability to identify pipeline construction opportunities with favorable projected financial returns;
- inability to raise financing for its identified pipeline construction opportunities; or
- inability to secure sufficient transportation commitments from potential customers due to competition from other pipeline construction projects or for other reasons.

Furthermore, even if ETP or Regency constructs a pipeline that it believes will be accretive, the pipeline may in fact adversely affect its results of operations or fail to achieve results projected prior to commencement of construction.

Expanding ETP's and Regency's business by constructing new pipelines and related facilities subjects ETP and Regency to risks.

One of the ways that ETP and Regency have grown their respective businesses is through the construction of additions to 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 ETP's and Regency's control and require the expenditure of significant amounts of capital to be financed through borrowings, the issuance of additional equity or from operating cash flow. If ETP or Regency undertakes these projects, they may not be completed on schedule or at all or at the budgeted cost. A variety of factors outside ETP's or Regency's 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 ETP's or Regency's results of operations and cash flows. Moreover, revenues may not increase immediately following the completion of a particular project. For instance, if ETP or Regency builds a new pipeline, the construction will occur over an extended period of time, but ETP or Regency, as applicable, may not materially increase its 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 ETP's and Regency's abilities to obtain commitments from producers in the area to utilize the newly constructed pipelines. In this regard, ETP and Regency 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 ETP's or Regency's expected investment return, which could adversely affect its results of operations and financial condition.

ETP and Regency depend on certain key producers for a significant portion of their supplies of natural gas. The loss of, or reduction in, any of these key producers could adversely affect ETP's or Regency's respective business and operating results.

ETP and Regency rely on a limited number of producers for a significant portion of their natural gas supplies. These contracts have terms that range from month-to-month to life of lease. As these contracts expire, ETP and Regency will have to negotiate extensions or renewals or replace the contracts with those of other suppliers. ETP and Regency may be unable to obtain new or renewed contracts on favorable terms, if at all. The loss of all or even a portion of the volumes of natural gas supplied by these producers and other customers, as a result of competition or otherwise, could have a material adverse effect on ETP's and Regency's business, results of operations, and financial condition.

ETP and Regency depend on key customers to transport natural gas through their pipelines.

ETP and Regency rely on a limited number of major shippers to transport certain minimum volumes of natural gas on their respective pipelines, and Regency maintains contracts for compression services with a limited number of key customers. The failure of the major shippers on ETP's, Regency's or their joint ventures' pipelines or of other key customers to fulfill their contractual obligations under these contracts could have a material adverse effect on the cash flow and results of operations of us, ETP, Regency or their joint ventures, as applicable, were unable to replace these customers under arrangements that provide similar economic benefits as these existing contracts.

Mergers among Sunoco Logistics' customers and competitors could result in lower volumes being shipped on its pipelines or products stored in or distributed through its terminals, or reduced crude oil marketing margins or volumes.

Mergers between existing customers could provide strong economic incentives for the combined entities to utilize their existing systems instead of Sunoco Logistics' systems in those markets where the systems compete. As a result, Sunoco Logistics could lose some or all of the volumes and associated revenues from these customers and could experience difficulty in replacing those lost volumes and revenues, which could materially and adversely affect our results of operations, financial position, or cash flows.

A portion of Sunoco Logistics' general and administrative services have been outsourced to third-party service providers. Fraudulent activity or misuse of proprietary data involving its outsourcing partners could expose us to additional liability.

Sunoco Logistics utilizes both affiliate entities and third parties in the processing of its information and data. Breaches of its security measures or the accidental loss, inadvertent disclosure or unapproved dissemination of proprietary information or sensitive or confidential data about Sunoco Logistics or its customers, including the potential loss or disclosure of such information or data as a result of fraud or other forms of deception, could expose Sunoco Logistics to a risk of loss or misuse of this information, result in litigation and potential liability for Sunoco Logistics, lead to reputational damage, increase compliance costs, or otherwise harm its business.

ETP and Regency's 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 ETP's and Regency's 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.

ETP and Regency are required to file tariff rates (also known as recourse rates) with the 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. ETP and Regency must also file with the FERC all negotiated rates that do not conform to our tariff rates and all changes to our tariff or negotiated rates. The FERC must approve or accept all rate filings for us to be allowed to charge such rates.

The FERC may review existing tariffs rates on its own initiative or upon receipt of a complaint filed by a third party. The 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. The FERC has recently exercised this authority with respect to several other pipeline companies. If the FERC were to initiate a proceeding against ETP or Regency and find that their rates were not just and reasonable or unduly discriminatory, the maximum rates customers could elect to pay ETP and Regency may be reduced and the reduction could have an adverse effect on their revenues and results of operations.

The costs of ETP's and Regency's interstate pipeline operations may increase and ETP or Regency may not be able to recover all of those costs due to FERC regulation of their rates. If ETP or Regency propose to change their tariff rates, their proposed rates may be challenged by the FERC or third parties, and the FERC may deny, modify or limit ETP's or Regency's proposed changes if they are unable to persuade the FERC that changes would result in just and reasonable rates that are not unduly discriminatory. ETP and Regency 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 ETP and Regency may be constrained by competitive factors from charging their tariff rates.

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

In July 2010, in response to an intervention and protest filed by BGLS regarding its rates with Trunkline LNG applicable to certain LNG expansions, the FERC determined that there was no reason at that time to expend the FERC's resources on a rate proceeding with respect to Trunkline LNG even though cost and revenue studies provided to the FERC indicated Trunkline LNG's revenues were in excess of its associated cost of service. 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.

The ability of interstate pipelines held in tax-pass-through entities, like us, to include an allowance for income taxes as a cost-of-service element in their regulated rates has been subject to extensive litigation before the FERC and the courts for a number of years. It is currently the FERC's policy to permit pipelines to include in cost-of-service a tax allowance to reflect actual or potential income tax liability on their public utility income attributable to all partnership or limited liability company interests, if the ultimate owner of the interest has an actual or potential income tax liability on such income. Whether a pipeline's owners have such actual or potential income tax liability will be reviewed by the FERC on a case-by-case basis. Under the FERC's policy, we thus remain eligible to include an income tax allowance in the tariff rates we charge for interstate natural gas transportation. The effectiveness of the FERC's policy and the application of that policy remains subject to future challenges, refinement or change by the FERC or the courts.

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

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

- operating 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. In addition, we cannot guarantee that the FERC will authorize tariff changes and other activities we might propose to do so in a timely manner and free from potentially burdensome conditions. Future changes to laws, regulations, policies and interpretations thereof in these areas may impair the ability of ETP's and Regency's interstate pipelines to compete for business, may impair their ability to recover costs or may increase the cost and burden of operation.

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

Transportation provided on ETP's common carrier interstate crude oil and refined products pipelines is subject to rate regulation by the FERC, which requires that tariff rates for transportation on these oil pipelines be just and reasonable and not unduly discriminatory. If ETP proposes new or changed rates, the FERC or interested persons may challenge those rates and the FERC is authorized to suspend the effectiveness of such rates for up to seven months and to investigate such rates. If, upon completion of an investigation, the FERC finds that the proposed rate is unjust or unreasonable, it is authorized to require the carrier to refund revenues in excess of the prior tariff during the term of the investigation. The 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 the FERC to authorize increases in the tariff rates of petroleum pipelines is price indexing. The FERC's ratemaking methodologies may limit our ability to set rates based on our costs or may delay the use of rates that reflect increased costs. In addition, if the 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 the 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, the FERC could order us to reduce pipeline rates prospectively and to pay refunds to shippers.

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

State regulatory measures could adversely affect the business and operations of ETP and Regency's midstream and intrastate pipeline and storage assets.

ETP's and Regency's midstream and intrastate transportation and storage operations are generally exempt from FERC regulation under the NGA, but FERC regulation still significantly affects their business and the market for their products. The rates, terms and conditions of service for the interstate services they provide in their intrastate gas pipelines and gas storage are subject to FERC regulation under Section 311 of the NGPA. ETP's 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 the FERC determine not to authorize rates equal to or greater than ETP's or Regency's costs of service, their cash flow would be negatively affected.

ETP and Regency's midstream and intrastate gas and oil transportation pipelines and their intrastate gas storage operations are subject to state regulation. All of the states in which they operate midstream assets, intrastate pipelines or intrastate storage facilities have adopted 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 ETP and Regency 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, ETP's or Regency's businesses may be adversely affected.

ETP's and Regency's 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.

ETP and Regency 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 ETP's and Regency's assets may become subject to 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 the FERC on a case-by-case basis, although the 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 the FERC, the courts or Congress. 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.

Intrastate transportation of NGLs is largely regulated by the state in which such transportation takes place. Lone Star's NGL Pipeline transports NGLs within the state of Texas and is subject to regulation by the TRRC. This NGLs transportation system offers services pursuant to an intrastate transportation tariff on file with the TRRC. Lone Star's NGL pipeline also commenced the interstate transportation of NGLs in 2013, which is subject to FERC's jurisdiction under the Interstate Commerce Act and the Energy Policy Act of 1992. Both intrastate and interstate NGL transportation services must be provided in a manner that is just, reasonable, and non-discriminatory. The tariff rates established for interstate services were based on a negotiated agreement; however, if FERC's rate making methodologies were imposed, they may, among other things, delay the use of rates that reflect increased costs and subject us to potentially burdensome and expensive operational, reporting and other requirements. Any of the foregoing could adversely affect revenues and cash flow related to these assets.

ETP and Regency may incur significant costs and liabilities resulting from performance of pipeline integrity programs and related repairs.

Pursuant to authority under the NGPSA and HLPSA, as amended by the PSI Act, the PIPES Act and the 2011 Pipeline Safety Act, PHMSA has established a series of rules requiring pipeline operators to develop and implement integrity management programs for gas transmission and hazardous liquid pipelines that, in the event of a pipeline leak or rupture could affect "high consequence areas," which are areas where a release could have the most significant adverse consequences, including high population areas, certain drinking water sources, and unusually sensitive ecological areas.

These regulations require operators of covered pipelines to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline operations that could impact a high consequence area;
- improve data collection, integration and analysis;
- repair and remediate the pipeline as necessary; and
- implement preventive and mitigating actions.

In addition, states have adopted regulations similar to existing PHMSA regulations for intrastate gathering and transmission lines. At this time, we cannot predict the ultimate cost of compliance with applicable pipeline integrity management regulations, as the cost will vary significantly depending on the number and extent of any repairs found to be necessary as a result of the pipeline integrity testing. We will continue our pipeline integrity testing programs to assess and maintain the integrity of our pipelines. The results of these tests could cause us to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines. Any changes to pipeline safety laws by Congress and regulations by PHMSA that result in more stringent or costly safety standards could have a significant adverse effect on us and similarly situated midstream operators. For instance, changes to regulations governing the safety of gas transmission pipelines and gathering lines are being considered by PHMSA, including, for example, revising the definitions of "high consequence areas" and "gathering lines" and strengthening integrity management requirements as they apply to existing regulated operators and to currently exempt operators should certain exemptions be removed.

ETP's and Regency's businesses involve hazardous substances and may be adversely affected by environmental regulation.

ETP's and Regency's operations are subject to stringent federal, state and local laws and regulations governing the discharge of materials into the environment, worker health and safety and protection of the environment. These laws and regulations may require the acquisition of permits for ETP's and Regency's operations, result in capital expenditures to manage, limit, or prevent emissions, discharges or releases of various materials from ETP's and Regency's pipelines, plants and facilities and impose substantial liabilities for pollution resulting from ETP's and Regency's operations. Several governmental authorities, such as the EPA have the power to enforce compliance with these laws and regulations and the permits issued under them and frequently mandate difficult and costly remediation measures and other actions. Failure to comply with these laws, regulations and permits may result in the assessment of significant administrative, civil and criminal penalties, the imposition of remedial obligations and the issuance of injunctive relief. Certain environmental laws impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances, hydrocarbons or wastes have been disposed or released, even under circumstances where the substances, hydrocarbons or wastes have been released by a predecessor operator. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by noise, odor or the release of hazardous substances, hydrocarbons or wastes into the environment.

ETP and Regency may incur substantial environmental costs and liabilities because of the underlying risk inherent to its operations. Although we have established financial reserves for our estimated environmental remediation liabilities, additional contamination or conditions may be discovered, resulting in increased remediation costs, liabilities for natural resource damages that could substantially increase our costs for site remediation projects. 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 changes that result in significantly more stringent and costly waste handling, emission standards, or storage, transport, disposal or remediation requirements could have a material adverse effect on ETP's and Regency's operations or financial position. For example, in EPA the 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 to further reduce NOx and other ozone precursor emissions. ETP and Regency have previously been able to satisfy the more stringent NOx emission reduction requirements that affect its compressor units in ozone non-attainment areas at reasonable cost, but there is no assurance that ETP and Regency will not incur material costs in the future to meet the new ozone standard.

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.

The adoption of climate change legislation or regulations restricting emissions of greenhouse gases could result in increased operating costs and reduced demand for the services we provide.

In December 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. Based on these findings, the EPA has adopted rules under the Clean Air Act that, among other things, establish PSD construction and Title V operating permit reviews for certain large stationary sources, which reviews could require securing PSD permits at covered facilities emitting greenhouse gases and meeting “best available control technology” standards for those greenhouse gas emissions. In addition, the EPA has adopted rules requiring the monitoring and reporting of greenhouse gas emissions from specified onshore and offshore production facilities and onshore processing, transmission and storage facilities in the United States on an annual basis, which include certain of our operations. While Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases, there has not been significant activity in the form of adopted legislation. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing greenhouse gas emissions by means of cap and trade programs. The adoption of any legislation or regulations that requires reporting of greenhouse gases or otherwise restricts emissions of greenhouse gases from our equipment and operations could require us to incur significant added costs to reduce emissions of greenhouse gases or could adversely affect demand for the natural gas and NGLs we gather and process or fractionate. Moreover, if Congress undertakes comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax, which could impose additional direct costs on operations and reduce demand for refined products, which could adversely affect the services we provide.

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. This legislation was signed into law by President Obama on July 21, 2010 and requires the 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 was 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 ETP's and Regency's operations and otherwise materially adversely affect their cash flow.

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

If one or more facilities that are owned by ETP or Regency or that deliver natural gas or other products to ETP or Regency are damaged by severe weather or any other disaster, accident, catastrophe or event, ETP's or Regency's operations could be significantly interrupted. Similar interruptions could result from damage to production or other facilities that supply ETP's or Regency's facilities or other stoppages arising from factors beyond its 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 ETP's or Regency's operations, or which causes it to make significant expenditures not covered by insurance, could reduce ETP's or Regency's cash available for paying distributions to its Unitholders, including us.

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, ETP and Regency may not be able to renew existing insurance policies or procure other desirable insurance on commercially reasonable terms, if at all. If ETP or Regency were to incur a significant liability for which it was not fully insured, it could have a material adverse effect on ETP's or Regency's financial position and results of operations, as applicable. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient if such an event were to occur.

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

The United States government has issued warnings that energy assets, including the 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 ETP's or Regency's facilities or pipelines, those of their customers, or in some cases, those of other pipelines could have a material adverse effect on ETP's or Regency's business, financial condition and results of operations.

Cybersecurity breaches and other disruptions could compromise our information and expose us to liability, which would cause our 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 personal identification 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, disruption of our operations, damage to our reputation, and cause a loss of confidence in our products and services, which could adversely affect our business.

ETP has an equity investment in AmeriGas and the value of this investment, and the cash distributions ETP expects to receive from this investment, are subject to the risks encountered by AmeriGas with respect to its business.

As of December 31, 2013, ETP owned approximately 22.1 million AmeriGas common units and, as a result of a sale of approximately 9.2 million AmeriGas common units in January 2014, ETP owned 12.9 million AmeriGas common units as of January 31, 2014. The value of ETP's investment in AmeriGas common units and the cash distributions it expects 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.

More stringent regulatory initiatives in the U.S. Gulf of Mexico in the aftermath of the Macondo well oil spill may result in increased costs and delays in offshore oil and natural gas exploration and production operations, which costs and delays could significantly decrease the volume of our business and have a material adverse effect on our results of operations, financial position and liquidity.

In response to an April 2010 fire and explosion aboard the Deepwater Horizon drilling rig and resulting oil spill from the Macondo well operated by a third party in ultra-deep water in the U.S. Gulf of Mexico, federal authorities have pursued a series of regulatory initiatives to address the direct impact of that incident and to prevent similar incidents in the future. Beginning in 2010 and continuing through 2013, the federal government, acting through the U.S. Department of the Interior, or DOI, and its implementing agencies that have since evolved into the present day Bureau of Ocean Energy Management and Bureau of Safety and Environmental Enforcement has issued various rules, Notices to Lessees and Operators and temporary drilling moratoria that impose or result in added environmental and safety measures upon exploration, development and production operators in the U.S. Gulf of Mexico. These regulatory initiatives may serve to effectively slow down the pace of drilling and production operations in the U.S. Gulf of Mexico due to adjustments in operating procedures and certification practices, increased lead times to obtain exploration and production plan reviews, develop drilling applications, and apply for and receive new well permits and thus result in increased costs for affected operators, some of whom are our customers. The increased regulations and cost of drilling operations could result in decreased drilling activity in the areas serviced by us. Furthermore, business decisions by operators not to drill in the areas serviced by us in the future owing to the more rigorous regulatory environmental or increased costs of operating also could result in a reduction in the future development and production of natural gas reserves in the vicinity of our facilities, which could adversely affect our business, financial condition results of operations and cash flows. Also, if similar events were to occur in the future in the U.S. Gulf of Mexico in areas where we conduct operations, the United States could elect to again issue directives to temporarily cease drilling activities and, in any event, may from time to time issue further safety and environmental laws and regulations regarding offshore oil and gas exploration and development, which developments could have a material adverse effect on our volume of business as well as our financial position, results of operations and liquidity.

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 and Sunoco's unionized employees.

As of December 31, 2013, approximately 12% of our workforce is 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 operations, and expose us to liability, which would cause our 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.

Our information technology infrastructure is critical to the efficient operation of our business and essential to our ability to perform day-today operations. Breaches in our information technology infrastructure or physical facilities, or other disruptions, could result in damage to our assets, safety incidents, damage to the environment, potential liability or the loss of contracts, and have a material adverse effect on our operations, financial position and results of operations.

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.

Regency’s contract compression operations depend on particular suppliers and is vulnerable to parts and equipment shortages and price increases, which could have a negative impact on its results of operations.

The principal manufacturers of components for Regency’s natural gas compression equipment include Caterpillar, Inc. for engines, Air-X-Changers for coolers, and Ariel Corporation for compressors and frames. Regency’s reliance on these suppliers involves several risks, including price increases and a potential inability to obtain an adequate supply of required components in a timely manner. Regency also relies primarily on two vendors, Spitzer Industries Corp. and Standard Equipment Corp., to package and assemble its compression units. Regency does not have long-term contracts with these suppliers or packagers, and a partial or complete loss of certain of these sources could have a negative impact on Regency’s results of operations and could damage its customer relationships. In addition, since Regency expects any increase in component prices for compression equipment or packaging costs will be passed on to Regency, a significant increase in their pricing could have a negative impact on Regency’s results of operations.

Mergers among Sunoco Logistics’ customers and competitors could result in lower volumes being shipped on its pipelines or products stored in or distributed through its terminals, or reduced crude oil marketing margins or volumes.

Mergers between existing customers could provide strong economic incentives for the combined entities to utilize their existing systems instead of Sunoco Logistics’ systems in those markets where the systems compete. As a result, Sunoco Logistics could lose some or all of the volumes and associated revenues from these customers and could experience difficulty in replacing those lost volumes and revenues, which could materially and adversely affect our results of operations, financial position, or cash flows.

A portion of Sunoco Logistics' general and administrative services have been outsourced to third-party service providers. Fraudulent activity or misuse of proprietary data involving its outsourcing partners could expose us to additional liability.

Sunoco Logistics utilizes both affiliate entities and third parties in the processing of its information and data. Breaches of its security measures or the accidental loss, inadvertent disclosure or unapproved dissemination of proprietary information or sensitive or confidential data about Sunoco Logistics or its customers, including the potential loss or disclosure of such information or data as a result of fraud or other forms of deception, could expose Sunoco Logistics to a risk of loss or misuse of this information, result in litigation and potential liability for Sunoco Logistics, lead to reputational damage, increase compliance costs, or otherwise harm its business.

A material decrease in demand or distribution of crude oil available for transport through Sunoco Logistics' pipelines or terminal facilities could materially and adversely affect our results of operations, financial position, or cash flows.

The volume of crude oil transported through Sunoco Logistics' crude oil pipelines and terminal facilities depends on the availability of attractively priced crude oil produced or received in the areas serviced by its assets. A period of sustained crude oil price declines could lead to a decline in drilling activity, production and import levels in these areas. Similarly, a period of sustained increases in the price of crude oil supplied from any of these areas, as compared to alternative sources of crude oil available to Sunoco Logistics' customers, could materially reduce demand for crude oil in these areas. In either case, the volumes of crude oil transported in Sunoco Logistics' crude oil pipelines and terminal facilities could decline, and it could likely be difficult to secure alternative sources of attractively priced crude oil supply in a timely fashion or at all. If Sunoco Logistics is unable to replace any significant volume declines with additional volumes from other sources, our results of operations, financial position, or cash flows could be materially and adversely affected.

Tax Risks to Common Unitholders

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

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

Despite the fact that we, ETP and Regency are each a limited partnership under Delaware law, we would each be treated as a corporation for federal income tax purposes unless we satisfy a "qualifying income" requirement. Based upon our current operations, we believe we, ETP and Regency satisfy the qualifying income requirement. Failing to meet the qualifying income requirement or a change in current law could cause us, ETP or Regency to be treated as a corporation for federal income tax purposes or otherwise subject us, ETP or R to taxation as an entity.

If we, ETP or Regency were treated as a corporation, 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 at varying rates. 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.

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 to additional taxation as an entity 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. At the state level, several states have been evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise, or other forms of taxation. Imposition of a similar tax on us in the jurisdictions in which we operate or in other jurisdictions to which we may expand could substantially reduce our case available for distribution to our unitholders.

The tax treatment of publicly traded partnerships or an investment in ETP or Regency's common units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present federal income tax treatment of publicly traded partnerships, including us, or an investment in ETP or Regency's common units may be modified by legislative, judicial or administrative changes and differing interpretations at any time. For example, from time to time, members of Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships. One such legislative proposal would have eliminated the qualifying income exception to the treatment of all publicly traded partnerships as corporations, upon which we rely for our, ETP's and Regency's treatment as a partnership for federal income tax purposes. We are unable to predict whether any of these changes or other proposals will be reintroduced or will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units. Any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible to meet the exception for certain publicly traded partnerships to be treated as partnerships for federal income tax purposes.

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 or our subsidiaries take, the market for our Common Units, ETP Common Units or Regency Common Units may be adversely affected and the costs of any such contest will reduce cash available for distributions to our Unitholders.

Neither we nor our subsidiaries have requested a ruling from IRS with respect to our treatment as partnerships for federal income tax purposes. The IRS may adopt positions that differ from the positions we or our subsidiaries take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we or our subsidiaries take. A court may not agree with some or all of the positions we or our subsidiaries take. Any contest with the IRS may materially and adversely impact the market for our Common Units, ETP's Common Units or Regency's Common Units and the prices at which they trade. In addition, the costs of any contest with the IRS will be borne by us or our subsidiaries, and therefore indirectly by us, as a Unitholder and as the owner of the general partner of interests in ETP and Regency, 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.

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 result in a decrease in 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 adjusted 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 of depreciation deductions and certain other items. In addition, because the amount realized includes a Unitholder's share of our nonrecourse liabilities, if a Unitholder sells units, the Unitholders 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, including IRAs and other retirement plans, will be "unrelated business taxable income" and will be taxable to them. Allocations and/or distributions to non-U.S. persons will be reduced by withholding taxes, imposed at the highest effective tax rate applicable to non-U.S. persons, and each non-U.S. person will be required to file United States federal and state income tax returns and pay tax on their share of our taxable income. If you are a tax exempt entity or non-U.S. person, you should consult your tax advisor before investing in our common units.

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 owns units in us, a successful IRS challenge could result in this subsidiary having a greater 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 generally 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 the subject of a securities loan (e.g. a loan 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 there are no specific rules governing the federal income tax consequences of loaning a partnership interest, a Unitholder whose units are the subject of a securities loan may be considered as having disposed of the loaned units. In that case, the Unitholder may 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 such disposition. Moreover, during the period of the loan, 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 of their units are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

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

When we, ETP or Regency issue additional units or engage in certain other transactions, we, ETP or Regency determine the fair market value of the assets and allocate any unrealized gain or loss attributable to such assets to the capital accounts of ETP's and Regency's Unitholders and us. Although ETP and Regency may from time to time consult with professional appraisers regarding valuation matters, including the valuation of its assets, ETP and Regency make many of the fair market value estimates of their assets themselves using a methodology based on the market value of their Common Units as a means to measure the fair market value of their assets. ETP's or Regency's methodology may be viewed as understating the value of ETP's or Regency's assets. In that case, there may be a shift of income, gain, loss and deduction between certain ETP or Regency Unitholders and us, which may be unfavorable to such ETP or Regency 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 ETP's or Regency's tangible assets and a lesser portion allocated to ETP's or Regency's intangible assets. The IRS may challenge ETP's or Regency's valuation methods, or our, ETP's or Regency's allocation of Section 743(b) adjustment attributable to ETP's or Regency's tangible and intangible assets, and allocations of income, gain, loss and deduction between us and certain of ETP's or Regency's 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, the ETP Unitholders or the Regency Unitholders. It also could affect the amount of gain on the sale of Common Units by our Unitholders, ETP's Unitholders or Regency's Unitholders and could have a negative impact on the value of our Common Units or those of ETP or Regency or result in audit adjustments to the tax returns of our, ETP's or Regency's Unitholders without the benefit of additional deductions.

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

We will be considered to have technically terminated as a partnership 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 during the applicable twelve-month period 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. A technical 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 relief procedure whereby a publicly traded partnership that has technically terminated may be permitted to provide only a single Schedule K-1 to unitholders for the two tax years within the fiscal year in which the termination occurs.

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, ETP or Regency conduct business or own property now or in the future, even if they do not live in any of those 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. Unitholders may be required to file state and local income tax returns and pay state and local income taxes in some or all of the jurisdictions. Further, Unitholders may be subject to penalties for failure to comply with those requirements. It is the responsibility of each Unitholder to file all federal, state and local tax returns.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

A description of our properties is included in “Item 1. Business.” In addition, we and our subsidiaries own an executive office building 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 subsidiaries’ 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. Our subsidiaries 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 subsidiaries’ pipelines were built were purchased in fee. ETP also owns and operates multiple natural gas and NGL storage facilities and owns or leases other processing, treating and conditioning facilities in connection with its 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 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, 2013, Sunoco is a defendant in seven cases, one of which was initiated by the State of New Jersey and two others by the Commonwealth of Puerto Rico with the more recent Puerto Rico action being a companion case alleging damages for additional sites beyond those at issue in the initial Puerto Rico action. Six of these cases are venued in a multidistrict litigation (“MDL”) proceeding in a New York federal court. The most recently filed Puerto Rico action is expected to be transferred to the MDL. The New Jersey and Puerto Rico 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.

Fact discovery has concluded with respect to an initial set of fewer than 20 sites each that will be the subject of the first trial phase in the New Jersey case and the initial Puerto Rico case. Insufficient information has been developed about the plaintiffs’ legal theories or the facts with respect to statewide natural resource damage claims to provide an analysis of the ultimate potential liability of Sunoco in these matters; however, it is reasonably possible that a loss may be realized. Management believes that an adverse determination with respect to one or more of the MTBE cases could have a significant impact on results of operations during the period in which any said adverse determination occurs, but does not believe that any such adverse determination would have a material adverse effect on the Partnership’s consolidated financial position.

In January 2012, Sunoco Logistics experienced a release on its refined products pipeline in Wellington, Ohio. In connection with this release, the PHMSA issued a Corrective Action Order under which Sunoco Logistics is obligated to follow specific requirements in the investigation of the release and the repaid and reactivation of the pipeline. Sunoco Logistics also entered into an Order on Consent with the EPA regarding the environmental remediation of the release site. All requirements of the Order of Consent with the EPA have been fulfilled and the Order has been satisfied and closed. Sunoco Logistics has also received a “No Further Action” approval from the Ohio EPA for all soil and groundwater remediation requirements. Sunoco Logistics has not received any proposed penalties associated with this release and continues to cooperate with both PHMSA and the EPA to complete the investigation of the incident and repair of the pipeline.

In 2012, the EPA issued a proposed consent agreement related to the releases that occurred at Sunoco Logistics’ pump station/tank farm in Barbers Hill, Texas and pump station/tank farm located in Cromwell, Oklahoma in 2010 and 2011, respectively. These matters were referred to the U.S. Department of Justice (“DOJ”) by the EPA. In November 2012, Sunoco Logistics received an initial assessment of $1.4 million associated with these releases. Sunoco Logistics is in discussions with the EPA and the DOJ on this matter and hopes to resolve the issue during 2014.

In September 2013, the Pennsylvania Department of Environmental Protection (“PADEP”) issued a Notice of Violation and proposed penalties in excess of $0.1 million based on alleged violations of various safety regulations relating to the November 2008 products release by Sunoco Pipeline L.P., a subsidiary of Sunoco Logistics, in Murrysville, Pennsylvania. Sunoco Logistics is currently in discussions with the PADEP. The timing or outcome of this matter cannot be reasonably determined at this time. However, we do not expect a material impact to the Partnership’s results of operations, cash flows or financial position.

Additionally, we have received notices of violations and potential fines under various federal, state and local provisions relating to the discharge of materials into the environment or protection of the environment. While we believe that even if any one or more of the environmental proceedings listed below were decided against us, it would not be material to our financial position, results of operations or cash flows, we are required to report environmental proceedings if we reasonably believe that such proceedings will result in monetary sanctions in excess of $0.1 million.

For a description of legal proceedings, see Note 11 to our consolidated financial statements.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

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

Parent Company

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

The Parent Company's common units are listed on the NYSE under the symbol "ETE." The following table sets forth, for the periods indicated, the high and low sales prices per ETE Common Unit, as reported on the NYSE Composite Tape, and the amount of cash distributions paid per ETE Common Unit for the periods indicated.

	Price Range [1]		Cash Distribution [2]
	High	Low	
Fiscal Year 2013:			
Fourth Quarter	$ 42.58	$ 32.01	$ 0.346
Third Quarter	34.20	29.47	0.336
Second Quarter	31.25	26.56	0.328
First Quarter	29.54	23.04	0.323
Fiscal Year 2012:			
Fourth Quarter	$ 24.10	$ 20.86	$ 0.318
Third Quarter	23.04	19.96	0.313
Second Quarter	21.56	17.00	0.313
First Quarter	22.24	19.43	0.313

(1) Prices and distributions have been adjusted to reflect the effect of the two-for-one split of ETE Common Units completed on January 27, 2014. See Note 8 to our consolidated financial statements.

(2) 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 January 31, 2014, there were approximately 138,204 individual common unitholders, which includes common units held in street name. Common units represent limited partner interest in us that entitle the holders to the rights and privileges specified in the Parent Company's Third Amended and Restated Agreement of Limited Partnership, as amended to date (the "Partnership Agreement").

As of December 31, 2013, common units represent an aggregate 99.48% limited partner interest in us. Our General Partner owns an aggregate 0.25% General Partner interest in us. Our common units are registered under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), and are listed for trading on the NYSE. Each holder of a common unit is entitled to one vote per unit on all matters presented to the limited partners for a vote. In addition, if at any time any person or group (other than our General Partner and its affiliates) owns beneficially 20% or more of all common units, any Common Units owned by that person or group may not be voted on any matter and are not considered to be outstanding when sending notices of a meeting of unitholders (unless otherwise required by law), calculating required votes, determining the presence of a quorum or for other similar purposes under our Partnership Agreement. The common units are entitled to distributions of Available Cash as described below under "Cash Distribution Policy."

Cash Distribution Policy

General. The Parent Company will distribute all of its "Available Cash" to its unitholders and its General Partner within 50 days following the end of each fiscal quarter.

Definition of Available Cash. Available Cash is defined in the Parent Company's 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 its business;
- comply with applicable law and/or debt instrument or other agreement; and
- provide funds for distributions to unitholders and its General Partner in respect of any one or more of the next four quarters.

The total amount of distributions declared is reflected in Note 8 to our consolidated financial statements.

Recent Sales of Unregistered Securities

None.

ITEM 6. SELECTED FINANCIAL DATA

The selected historical 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 accompanying notes thereto included elsewhere in this report. The amounts in the table below, except per unit data, are in millions.

In 2013, Southern Union disposed of the assets of MGE and NEG. The results of continuing operations of the distribution operations were reflected as income from discontinued operations. In 2012, ETP sold Canyon and the results of continuing operations of Canyon were reflected as discontinued operations.

	Years Ended December 31,				
Statement of Operations Data:	2013	2012	2011	2010	2009
Total revenues	$ 48,335	$ 16,964	$ 8,190	$ 6,556	$ 5,378
Operating income	1,551	1,360	1,237	1,044	1,047
Income from continuing operations	282	1,383	531	345	692
Basic income from continuing operations per limited partner unit	0.33	0.59	0.69	0.44	0.99
Diluted income from continuing operations per limited partner unit	0.33	0.59	0.69	0.44	0.99
Cash distribution per unit	1.33	1.26	1.22	1.08	1.07
Balance Sheet Data (at period end):					
Total assets	50,330	48,904	20,897	17,379	12,161
Long-term debt, less current maturities	22,562	21,440	10,947	9,346	7,751
Total equity	16,279	16,350	7,388	6,248	3,220

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

(Tabular dollar and unit amounts, except per unit data, are in millions)

Energy Transfer Equity, L.P. is a Delaware limited partnership whose common units are publicly traded on the NYSE under the ticker symbol "ETE." ETE was formed in September 2002 and completed its initial public offering in February 2006.

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" of this report.

Unless the context requires otherwise, references to "we," "us," "our," the "Partnership" and "ETE" mean Energy Transfer Equity, L.P. and its consolidated subsidiaries, which include ETP, ETP GP, ETP LLC, Regency, Regency GP, Regency LLC, Panhandle (or Southern Union prior to its merger into Panhandle in January 2014), Sunoco, Sunoco Logistics and Holdco. References to the "Parent Company" mean Energy Transfer Equity, L.P. on a stand-alone basis.

OVERVIEW

Energy Transfer Equity, L.P. directly and indirectly owns equity interests in ETP and Regency, both publicly traded master limited partnerships engaged in diversified energy-related services.

At December 31, 2013, our interests in ETP and Regency consisted of 100% of the respective general partner interests and IDRs, as well as the following:

	ETP	Regency
Units held by wholly-owned subsidiaries:		
Common units	49.6	26.3
ETP Class H units	50.2	—
Units held by less than wholly-owned subsidiaries:		
Common units	—	31.4
Regency Class F units	—	6.3

The Parent Company's principal sources of cash flow are derived from its direct and indirect investments in the limited partner and general partner interests in ETP and Regency, both of which are publicly traded master limited partnerships engaged in diversified energy-related services. The Parent Company's primary cash requirements are for distributions to its partners, general and administrative expenses, debt service requirements and at ETE's election, capital contributions to ETP and Regency in respect of ETE's general partner interests in ETP and Regency. The Parent Company-only assets and liabilities are not available to satisfy the debts and other obligations of subsidiaries.

In order to fully understand the financial condition and results of operations of the Parent Company on a stand-alone basis, we have included discussions of Parent Company matters apart from those of our consolidated group.

General

Our primary objective is to increase the level of our distributable cash flow to our unitholders over time by pursuing a business strategy that is currently focused on growing our subsidiaries' natural gas and NGL businesses through, among other things, pursuing certain construction and expansion opportunities relating to our subsidiaries' existing infrastructure and acquiring certain strategic operations and businesses or assets. The actual amounts of cash that we will have available for distribution will primarily depend on the amount of cash our subsidiaries generate from their operations.

As a result of the Holdco Acquisition in April 2013, our reportable segments were re-evaluated and currently reflect the following reportable segments:

- Investment in ETP, including the consolidated operations of ETP;
- Investment in Regency, including the consolidated operations of Regency; and
- Corporate and Other, including the following:
  - activities of the Parent Company; and

- the goodwill and property, plant and equipment fair value adjustments recorded as a result of the 2004 reverse acquisition of Heritage Propane Partners, L.P.

Each of the respective general partners of ETP and Regency have separate operating management and boards of directors. We control ETP and Regency through our ownership of their respective general partners.

Recent Developments

SUGS Contribution

On April 30, 2013, Southern Union completed its contribution to Regency of all of the issued and outstanding membership interest in Southern Union Gathering Company, LLC, and its subsidiaries, including SUGS (the "SUGS Contribution"). The consideration paid by Regency in connection with this transaction consisted of (i) the issuance of approximately 31.4 million Regency common units to Southern Union, (ii) the issuance of approximately 6.3 million Regency Class F units to Southern Union, (iii) the distribution of $463 million in cash to Southern Union, net of closing adjustments, and (iv) the payment of $30 million in cash to a subsidiary of ETP.

ETP Note Exchange

On June 24, 2013, ETP completed the exchange of approximately $1.09 billion aggregate principal amount of Southern Union's outstanding senior notes, comprising 77% of the principal amount of the 7.6% Senior Notes due 2024, 89% of the principal amount of the 8.25% Senior Notes due 2029 and 91% of the principal amount of the Junior Subordinated Notes due 2066. These notes were exchanged for new notes issued by ETP with the same coupon rates and maturity dates. In conjunction with this transaction, Southern Union entered into intercompany notes payable to ETP, which provide for the reimbursement by Southern Union of ETP's payments under the newly issued notes.

Sale of AmeriGas Common Units

On July 12, 2013, ETP sold 7.5 million AmeriGas common units for net proceeds of $346 million. Net proceeds from this sale were used to repay borrowings under the ETP Credit Facility. In January 2014, ETP sold 9.2 million AmeriGas common units for net proceeds of $381 million. Net proceeds from these sales were used to repay borrowings under the ETP Credit Facility and for general partnership purposes.

Class H Units

Pursuant to an Exchange and Redemption Agreement previously entered into between ETP, ETE and ETE Holdings, ETP redeemed and cancelled 50.2 million of its Common Units representing limited partner interests (the "Redeemed Units") owned by ETE Holdings on October 31, 2013 in exchange for the issuance by ETP to ETE Holdings of a new class of limited partner interest in ETP (the "Class H Units"), which are generally entitled to (i) allocations of profits, losses and other items from ETP corresponding to 50.05% of the profits, losses, and other items allocated to ETP by Sunoco Partners with respect to the IDRs and general partner interest in Sunoco Logistics held by Sunoco Partners, (ii) distributions from available cash at ETP for each quarter equal to 50.05% of the cash distributed to ETP by Sunoco Partners with respect to the IDRs and general partner interest in Sunoco Logistics held by Sunoco Partners for such quarter and, to the extent not previously distributed to holders of the Class H Units, for any previous quarters and (iii) incremental additional cash distributions in the aggregate amount of $329 million, to be payable by ETP to ETE Holdings over 15 quarters, commencing with the quarter ended September 30, 2013 and ending with the quarter ending March 31, 2017. The incremental cash distributions referred to in clause (iii) of the previous sentence are intended to offset a portion of the IDR subsidies previously granted by ETE to ETP in connection with the Citrus Merger, the Holdco Transaction and the Holdco Acquisition. In connection with the issuance of the Class H Units, ETE and ETP also agreed to certain adjustments to the prior IDR subsidies in order to ensure that the IDR subsidies are fixed amounts for each quarter to which the IDR subsidies are in effect. For a summary of the net IDR subsidy amounts resulting from this transaction, see "Liquidity and Capital Resources — Cash Distributions — Cash Distributions Paid by ETP" below.

LNG Export Project

On August 7, 2013, Lake Charles Exports, LLC, an entity owned by BG LNG Services, LLC and Trunkline LNG Holdings, LLC, received an order from the Department of Energy conditionally granting authorization to export up to 15 million metric tonnes per annum of LNG to non-free trade agreement countries from the existing LNG import terminal owned by Trunkline LNG Company, LLC, which is located in Lake Charles, Louisiana. Lake Charles Exports, LLC previously received approval to export LNG from the Lake Charles facility to free trade agreement countries on July 22, 2011. In October 2013, Trunkline and BG Group announced their entry into a project development agreement to jointly develop the LNG export project at the existing Trunkline LNG import terminal.

Sale of Southern Union's Distribution Operations

In September 2013, Southern Union completed its sale of the assets of MGE for an aggregate purchase price of $975 million, net of customary post-closing adjustments. In December 2013, Southern Union completed its sale of the assets of NEG for cash proceeds of $40 million, subject to customary post-closing adjustments, and the assumption of $20 million of debt.

Regency's Pending Acquisition of PVR

In October 2013, Regency entered into a merger agreement with PVR pursuant to which Regency intends to merge with PVR. This merger will be a unit-for-unit transaction plus a one-time $37 million cash payment to PVR unitholders which represents total consideration of $5.6 billion, including the assumption of net debt of $1.8 billion. The PVR Acquisition is expected to enhance our geographic diversity with a strategic presence in the Marcellus and Utica shales in the Appalachian Basin and the Granite Wash in the Mid-Continent region. The PVR Acquisition is expected to close in late March 2014, subject to receipt of the affirmative vote of a majority of the PVR common units outstanding at a meeting scheduled to be held on March 20, 2014 and subject to the satisfaction of other customary closing conditions.

Regency's Pending Acquisition of Eagle Rock's Midstream Business

In December 2013, Regency entered into an agreement to purchase Eagle Rock's midstream business for $1.3 billion. This acquisition is expected to complement Regency's core gathering and processing business and further diversify Regency's basin exposure in the Texas Panhandle, East Texas and South Texas. The Eagle Rock Midstream Acquisition is expected to close in the second quarter of 2014, subject to receipt of the affirmation vote of a majority of the outstanding Eagle Rock common units and subject to the satisfaction of other customary closing conditions, including anti-trust clearance under Hart-Scott Rodino Antitrust Improvements Act.

Regency's Acquisition of Hoover Energy

On February 3, 2014, Regency completed its previously announced acquisition of the midstream assets of Hoover Energy. The consideration paid by Regency in exchange for the acquired Hoover entities was valued at $282 million (subject to customary post-closing adjustments) and consisted of (i) 4.0 million Regency Common Units issued to Hoover Energy and (ii) $184 million in cash. A portion of the consideration is being held in escrow as security for certain indemnification claims. Regency financed the cash portion of the purchase price through borrowings under its revolving credit facility.

ETP's Retail Acquisition

In October 2013, La Grange Acquisition, L.P., an indirect wholly-owned subsidiary of ETP, acquired convenience store operator MACS with a network of approximately 300 company-owned and dealer locations. These operations are reflected in ETP's retail marketing operations, along with the retail marketing operations owned by Holdco, beginning in the fourth quarter of 2013.

Second Fractionator at Lone Star's Mont Belvieu Facility

In November 2013, ETP announced that Lone Star has placed in service a second 100,000 barrel-per-day NGL fractionator at its facility in Mont Belvieu, Texas, bringing Lone Star's total fractionation capacity at Mont Belvieu to 200,000 barrels per day.

ETE Refinancing Activities

In December 2013, ETE completed a tender offer for a portion of its outstanding 7.50% Senior Notes due 2020. In conjunction with the tender offer, ETE completed a comprehensive refinancing of its existing debt, which included the public offering of $450 million aggregate principal amount of its 5.875% Senior Notes due 2024, a new $1 billion term loan facility, and a new $600 million revolving credit facility. In February 2014, ETE increased the capacity on the ETE Revolving Credit Facility to $800 million and expects to utilize the additional capacity to fund the purchase of $400 million of Regency common units in connection with Regency's pending Eagle Rock acquisition.

Panhandle Merger

On January 10, 2014, Panhandle consummated a merger with Southern Union, the indirect parent of Panhandle, and PEPL Holdings, the sole limited partner of Panhandle, pursuant to which each of Southern Union and PEPL Holdings were merged with and into Panhandle (the "Panhandle Merger"), with Panhandle surviving the Panhandle Merger. In connection with the Panhandle Merger, Panhandle assumed Southern Union's obligations under its 7.6% Senior Notes due 2024, 8.25% Senior Notes due 2029 and the Junior Subordinated Notes due 2066. At the time of the Panhandle Merger, Southern Union did not have operations of its own, other than its ownership of Panhandle and noncontrolling interest in PEI Power II, LLC, Regency (31.4 million Regency Common Units and 6.3 million Regency Class F Units), and ETP (2.2 million ETP Common Units). In connection with the Panhandle Merger, Panhandle also assumed PEPL Holdings' guarantee of $600 million of Regency senior notes.

Trunkline LNG Transaction

On February 19, 2014, ETE and ETP completed the transfer to ETE of Trunkline LNG, the entity that owns a LNG regasification facility in Lake Charles, Louisiana, from ETP in exchange for the redemption by ETP of 18.7 million ETP Common Units held by ETE. The transaction was effective as of January 1, 2014.

Results of Operations

Year Ended December 31, 2013 Compared to the Year Ended December 31, 2012

ETP's contribution of SUGS to Regency on April 30, 2013 was recorded by Regency as a reorganization of entities under common control. Accordingly, Regency retrospectively adjusted its consolidated financial statements to reflect the consolidation of SUGS beginning March 26, 2012 (the date ETE acquired Southern Union, the previous parent of SUGS). Amounts reflected herein for Regency reflect its retrospective consolidation of SUGS.

ETP maintains continuing involvement with SUGS through its affiliation with Regency, including ETP's investment in Regency common and Class F units received as partial consideration for the SUGS contribution. Accordingly, ETP did not record the results of SUGS as discontinued operations; therefore, the results of ETP included herein reflected consolidation of SUGS from March 26, 2012 through April 30, 2013.

As a result, the results of SUGS for March 26, 2012 through April 30, 2013 are included in segment results for both the investment in ETP and the investment in Regency segments in the "Segment Operating Results" section below and in Segment Adjusted EBITDA for both segments in the consolidated results table below. The results of SUGS during that period are separately eliminated in the consolidated results below in order to reconcile to ETE's consolidated net income.

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). Segment 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.

Consolidated Results

	Years Ended December 31, 2013	2012	Change
Segment Adjusted EBITDA:			
Investment in ETP	$ 3,953	$ 2,744	$ 1,209
Investment in Regency	608	517	91
Corporate and Other	(43)	(52)	9
Adjustments and eliminations	(151)	(104)	(47)
Total	4,367	3,105	1,262
Depreciation and amortization	(1,313)	(871)	(442)
Interest expense, net of interest capitalized	(1,221)	(1,018)	(203)
Bridge loan related fees	—	(62)	62
Gain on deconsolidation of Propane Business	—	1,057	(1,057)
Gain on sale of AmeriGas common units	87	—	87
Goodwill impairment	(689)	—	(689)
Gains (losses) on interest rate derivatives	53	(19)	72
Non-cash unit-based compensation expense	(61)	(47)	(14)
Unrealized gains on commodity risk management activities	48	10	38
LIFO valuation adjustments	3	(75)	78
Losses on extinguishments of debt	(162)	(123)	(39)
Adjusted EBITDA related to discontinued operations	(76)	(99)	23
Adjusted EBITDA related to unconsolidated affiliates	(727)	(647)	(80)
Equity in earnings of unconsolidated affiliates	236	212	24
Non-operating environmental remediation	(168)	—	(168)
Other, net	(2)	14	(16)
Income from continuing operations before income tax expense	375	1,437	(1,062)
Income tax expense	93	54	39
Income from continuing operations	282	1,383	(1,101)
Income (loss) from discontinued operations	33	(109)	142
Net income	$ 315	$ 1,274	$ (959)

See the detailed discussion of Segment Adjusted EBITDA in the Segment Operating Results section below.

The year ended December 31, 2012 was impacted by multiple transactions. Additional information has been provided in "Supplemental Pro Forma Information" below, which provides pro forma information assuming the transactions had occurred at the beginning of the period.

Depreciation and Amortization. Depreciation and amortization increased primarily as a result of acquisitions and growth projects including:

- depreciation and amortization related to Sunoco Logistics of $265 million in 2013 compared to $63 million from October 5, 2012 through December 31, 2012;
- depreciation and amortization related to Sunoco of $113 million in 2013 compared to $32 million from October 5, 2012 through December 31, 2012;
- depreciation and amortization related to Southern Union of $189 million in 2013 compared to $179 million from March 26, 2012 through December 31, 2012; and
- additional depreciation and amortization recorded from assets placed in service in 2013 and 2012.

Interest Expense, Net of Interest Capitalized. Interest expense increased primarily due to the following:

- interest expense related to Sunoco Logistics of $76 million in 2013 compared to $14 million from October 5, 2012 through December 31, 2012;
- interest expense related to Sunoco of $33 million in 2013 compared to $9 million from October 5, 2012 through December 31, 2012;
- incremental interest expense due to ETP's issuance of $1.25 billion of senior notes in January 2013 and $1.5 billion of senior notes in September 2013; and
- an increase of $42 million related to Regency primarily due to its issuance of $700 million of senior notes in October 2012, $600 million of senior notes in April 2013 and $400 million of senior notes in September 2013; partially offset by
- a reduction of $25 million for the Parent Company primarily related to a $1.1 billion principal paydown of the Parent Company's $2 billion term loan in April 2013.

Bridge Loan Related Fees. The bridge loan commitment fee recognized during the year ended December 31, 2012 was incurred in connection with the Southern Union Merger. The Parent Company obtained permanent financing for the transaction through a $2 billion senior secured term loan which was funded upon closing of the Southern Union Merger on March 26, 2012.

Gain on Deconsolidation of Propane Business. ETP recognized a gain on deconsolidation related to the contribution of its Propane Business to AmeriGas in January 2012.

Gain on Sale of AmeriGas Common Units. In July 2013, ETP sold 7.5 million of the AmeriGas common units that ETP originally received in connection with the contribution of its Propane Business to AmeriGas in January 2012. ETP recorded a gain based on the sale proceeds in excess of the carrying amount of the units sold.

Goodwill Impairment. In 2013, Trunkline LNG recorded a $689 million goodwill impairment. The decline in the estimated fair value was primarily due to changes related to (i) the structure and capitalization of the planned LNG export project at Trunkline LNG's Lake Charles facility, (ii) an analysis of current macroeconomic factors, including global natural gas prices and relative spreads, as of the date of our assessment (iii) judgments regarding the prospect of obtaining regulatory approval for a proposed LNG export project and the uncertainty associated with the timing of such approvals, and (iv) changes in assumptions related to potential future revenues from the import facility and the proposed export facility. An assessment of these factors in the fourth quarter of 2013 led to a conclusion that the estimated fair value of the Trunkline LNG reporting unit was less than its carrying amount.

Gains (Losses) on Interest Rate Derivatives. Gains on interest rate derivatives during the year ended December 31, 2013 resulted from increases in forward interest rates, which caused our forward-starting swaps to increase in value. These swaps are marked to fair value for accounting purposes with changes in value recorded in earnings each period. Conversely, decreases in forward interest rates resulted in losses on interest rate derivatives during the year ended December 31, 2012.

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

LIFO Valuation Adjustments. LIFO valuation reserve adjustments were recorded for the inventory associated with Sunoco's retail marketing operations as a result of commodity price changes between periods.

Losses on Extinguishments of Debt. For the year ended December 31, 2013, the loss on extinguishment of debt was primarily related to ETE's refinancing transactions completed in December 2013. For the year ended December 31, 2012, ETP recognized a loss on extinguishment of debt in connection with its repurchase of approximately $750 million in aggregate principal amount of senior notes in January 2012. In addition, Regency recognized a $7 million loss on extinguishment of debt in connection with its repurchase of senior notes in June 2013 and an $8 million loss in connection with its repurchases of senior notes in May 2012.

Adjusted EBITDA Related to Discontinued Operations. For the year ended December 31, 2013, amounts reflected Southern Union's distribution operations through the date of sale. Southern Union completed the sales of the assets of MGE in September 2013 and the assets of NEG in December 2013. For the year ended December 31, 2012, amounts reflected 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. See additional discussion of results in "Segment Operating Results" below.

Adjusted EBITDA Related to Unconsolidated Affiliates and Equity in Earnings of Unconsolidated Affiliates. Amounts reflected primarily include our proportionate share of such amounts related to AmeriGas, FEP, HPC and MEP, as well as Citrus beginning March 26, 2012. See additional discussion of results in "Segment Operating Results" below.

Non-Operating Environmental Remediation. Non-operating environmental remediation was primarily related to Sunoco's recognition of environmental obligations related to closed sites.

Other, net. Includes amortization of regulatory assets and other income and expense amounts.

Income Tax Expense. Income tax expense increased primarily due to the acquisitions of Southern Union and Sunoco in 2012, both of which are taxable corporations.

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 Propane Transaction, Sunoco Merger and Holdco Transaction for the years 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:

	ETE Historical	Propane Transaction[a]	Sunoco Historical[b]	Southern Union Historical[c]	Holdco Pro Forma Adjustments[d]	Pro Forma
REVENUES	$ 16,964	$ (93)	$ 35,258	$ 443	$ (12,174)	$ 40,398
COSTS AND EXPENSES:						
Cost of products sold and operating expenses	14,204	(80)	33,142	302	(11,193)	36,375
Depreciation and amortization	871	(4)	168	49	76	1,160
Selling, general and administrative	529	(1)	459	11	(119)	879
Impairment charges	—		124		(22)	102
Total costs and expenses	15,604	(85)	33,893	362	(11,258)	38,516
OPERATING INCOME	1,360	(8)	1,365	81	(916)	1,882
OTHER INCOME (EXPENSE):						
Interest expense, net of interest capitalized	(1,080)	(24)	(123)	(50)	2	(1,275)
Equity in earnings of affiliates	212	19	41	16	5	293
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	(123)	115	—	—	—	(8)
Losses on interest rate derivatives	(19)	—	—	—	—	(19)
Other, net	30	2	118	(2)	(2)	146
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE (BENEFIT)	1,437	(953)	2,545	45	(2,055)	1,019
Income tax expense (benefit)	54	—	956	12	(871)	151
INCOME FROM CONTINUING OPERATIONS	$ 1,383	$ (953)	$ 1,589	$ 33	$ (1,184)	$ 868

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

	ETE Historical	Propane Transaction[a]	Sunoco Historical[b]	Southern Union Historical[c]	Holdco Pro Forma Adjustments[d]	Pro Forma
REVENUES	$ 8,190	$ (1,427)	$ 45,328	$ 1,997	$ (16,528)	$ 37,560
COSTS AND EXPENSES:						
Cost of products sold and operating expenses	6,114	(1,174)	44,119	1,338	(16,677)	33,720
Depreciation and amortization	586	(78)	335	204	(2)	1,045
Selling, general and administrative	253	(47)	598	42	(56)	790
Impairment charges	—	—	2,629	—	(2,569)	60
Total costs and expenses	6,953	(1,299)	47,681	1,584	(19,304)	35,615
OPERATING INCOME	1,237	(128)	(2,353)	413	2,776	1,945
OTHER INCOME (EXPENSE):						
Interest expense, net of interest capitalized	(740)	(40)	(172)	(218)	29	(1,141)
Equity in earnings of affiliates	117	148	15	99	(158)	221
Gains (losses) on non-hedged interest rate derivatives	(78)	—	—	—	—	(78)
Impairment charges	(5)	—	—	—	—	(5)
Other, net	17	2	44	—	(2)	61
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE (BENEFIT)	548	(18)	(2,466)	294	2,645	1,003
Income tax expense (benefit)	17	(4)	(1,063)	80	1,070	100
INCOME FROM CONTINUING OPERATIONS	$ 531	$ (14)	$ (1,403)	$ 214	$ 1,575	$ 903

(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.

- 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.

Segment Operating Results

Investment in ETP

	Years Ended December 31, 2013	Years Ended December 31, 2012	Change
Revenues	$ 46,339	$ 15,702	$ 30,637
Cost of products sold	41,204	12,266	28,938
Gross margin	5,135	3,436	1,699
Unrealized (gains) losses on commodity risk management activities	(51)	9	(60)
Operating expenses, excluding non-cash compensation expense	(1,376)	(949)	(427)
Selling, general and administrative, excluding non-cash compensation expense	(448)	(406)	(42)
Adjusted EBITDA related to discontinued operations	76	99	(23)
Adjusted EBITDA related to unconsolidated affiliates	629	480	149
Other, net	(12)	75	(87)
Segment Adjusted EBITDA	$ 3,953	$ 2,744	$ 1,209

Gross Margin. For the year ended December 31, 2013 compared to the prior year, ETP's gross margin increased primarily as a result of the net impact of the following:

- The year ended December 31, 2013 reflected a full year of operations of Sunoco Logistics and ETP's retail marketing operations which were acquired October 5, 2012. Gross margin included in our consolidated results related to Sunoco Logistics and ETP's retail marketing operations increased $761 million and $693 million, respectively, between periods.

- Revenues from ETP's interstate transportation and storage operations increased $200 million primarily as a result of ETP's consolidation of Southern Union's transportation and storage operations beginning March 26, 2012.

- Gross margin related to ETP's NGL transportation and services operations increased $183 million as a result of (i) increases in transportation margin as a result of higher volumes transported out of West Texas due to the completion expansion projects and (ii) higher processing and fractionation margin due to the completion of Lone Star's fractionators in December 2012 and December 2013.

- These increases were partially offset by a decrease of $82 million in gross margin related to ETP's intrastate transportation and storage operations primarily due to the cessation of long-term transportation contracts.

- These increases were further offset by a decrease of $10 million in gross margin related to ETP's midstream operations primarily related to the deconsolidation of SUGS.

Unrealized (Gains) Losses on Commodity Risk Management Activities. Unrealized (gains) losses on commodity risk management activities primarily reflected the net impact from unrealized gains and losses on natural gas storage and non-storage derivatives, as well as fair value adjustments to inventory. The increase in unrealized gains on commodity risk management activities for 2013 compared to 2012 was primarily attributable to natural gas storage inventory and related derivatives.

Operating Expenses, Excluding Non-Cash Compensation Expense. For the year ended December 31, 2013 compared to the prior year, ETP's operating expense increased primarily as a result of a full year of operations related to Sunoco Logistics and ETP's retail marketing operations which were acquired on October 5, 2012. Operating expenses included in our consolidated results related to Sunoco Logistics and ETP's retail marketing operations increased $69 million and $316 million, respectively, between periods. In addition, ETP's interstate transportation and storage's operating expenses increased $77 million primarily as a result of ETP's consolidation of Southern Union. Operating expenses for ETP's NGL transportation and services operations increased approximately $49 million primarily due to additional expenses from assets being placed in service. These increases were partially offset by decreases in ETP's operating expenses due to its deconsolidation of certain operations during the periods, including ETP's retail propane operations in January 2012 and SUGS in April 2013.

Selling, General and Administrative, Excluding Non-Cash Compensation Expense. For the year ended December 31, 2013 compared to the prior year, ETP's selling, general and administrative expenses increased primarily as a result of a full year of operations related to Sunoco Logistics and ETP's retail marketing operations which were acquired on October 5, 2012. Selling, general and administrative expenses included in our consolidated results related to Sunoco Logistics and ETP's retail marketing operations increased $78 million and $84 million, respectively, between periods. These increases were partially offset by decreases in ETP's interstate transportation and storage operations and midstream operations of $65 million and $36 million, respectively, primarily as a result of merger-related expenses recorded in 2012 and cost reduction initiatives in 2013.

Adjusted EBITDA Related to Discontinued Operations. In 2013, amounts reflect Southern Union's distribution operations through the date of sale. Southern Union completed the sales of the assets of MGE in September 2013 and the assets of NEG in December 2013. In 2012, 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.

Adjusted EBITDA Related to Unconsolidated Affiliates. ETP's Adjusted EBITDA related to unconsolidated affiliates for the years ended December 31, 2013 and 2012 consisted of the following:

	Years Ended December 31,		
	2013	2012	Change
AmeriGas	$ 175	$ 139	$ 36
Citrus	296	228	68
FEP	75	77	(2)
Regency	66	—	66
Other	17	36	(19)
Total Adjusted EBITDA related to unconsolidated affiliates	$ 629	$ 480	$ 149

Amounts reflected above include a partial period for Citrus and AmeriGas in 2012 and a partial period for Regency in 2013.

Other. Other amounts in 2013 were primarily related to Sunoco's recognition of environmental obligations related to closed sites. Other amounts in 2012 were primarily related to Sunoco's LIFO valuation adjustments.

Investment in Regency

	Years Ended December 31,		
	2013	2012	Change
Revenues	$ 2,521	$ 2,000	$ 521
Cost of products sold	1,793	1,387	406
Gross margin	728	613	115
Unrealized (gains) losses on commodity risk management activities	9	(5)	14
Operating expenses, excluding non-cash compensation expense	(289)	(228)	(61)
Selling, general and administrative, excluding non-cash compensation expense	(81)	(95)	14
Adjusted EBITDA related to unconsolidated affiliates	250	222	28
Other, net	(9)	10	(19)
Segment Adjusted EBITDA	$ 608	$ 517	$ 91

Gross Margin. Regency's gross margin increased for the year ended December 31, 2013 compared to the prior year primarily due to increased volumes in Regency's South and West Texas gathering and processing operations.

Operating Expenses, Excluding Non-Cash Compensation Expense. Regency's operating expenses increased primarily due to the consolidation of SUGS beginning March 26, 2012 and increased pipeline and plant operating activity from organic growth.

Selling, General and Administrative, Excluding Non-Cash Compensation Expense. Regency's selling, general and administrative expenses decreased due to the elimination of the amount allocated to SUGS assets by the previous parent and the decrease in management fees paid to ETE, partially offset by an increase in legal and consulting fees.

Adjusted EBITDA Related to Unconsolidated Affiliates. Regency's adjusted EBITDA related to unconsolidated affiliates increased $30 million primarily due to the impact from Lone Star.

Other. Regency's other decreased primarily as the result of recognition of a one-time producer payment received in March 2012 related to an assignment of certain contracts.

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

Consolidated Results

	Years Ended December 31,		
	2012	2011	Change
Segment Adjusted EBITDA:			
Investment in ETP	$ 2,744	$ 1,781	$ 963
Investment in Regency	517	420	97
Corporate and Other	(52)	(29)	(23)
Adjustments and Eliminations	(104)	(41)	(63)
Total	3,105	2,131	974
Depreciation and amortization	(871)	(586)	(285)
Interest expense, net of interest capitalized	(1,018)	(740)	(278)
Bridge loan related fees	(62)	—	(62)
Gain on deconsolidation of Propane Business	1,057	—	1,057
Losses on non-hedged interest rate derivatives	(19)	(78)	59
Non-cash unit-based compensation expense	(47)	(42)	(5)
Unrealized gains on commodity risk management activities	10	7	3
LIFO valuation adjustments	(75)	—	(75)
Losses on extinguishments of debt	(123)	—	(123)
Adjusted EBITDA related to discontinued operations	(99)	(23)	(76)
Adjusted EBITDA related to unconsolidated affiliates	(647)	(231)	(416)
Equity in earnings of unconsolidated affiliates	212	117	95
Other, net	14	(7)	21
Income from continuing operations before income tax expense	1,437	548	889
Income tax expense	54	17	37
Income from continuing operations	1,383	531	852
Loss from discontinued operations	(109)	(3)	(106)
Net income	$ 1,274	$ 528	$ 746

See the detailed discussion of Segment Adjusted EBITDA in the Segment Operating Results section 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 to 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 2012 and 2011; partially offset by
- the deconsolidation of ETP's Propane Business in January 2012, which had recognized depreciation of $4 million and $82 million for years ended December 31, 2012 and 2011, respectively.

Interest Expense, Net of Interest Capitalized. Interest expense increased primarily due to:

- interest expense of $130 million recorded by Southern Union 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 to December 31, 2012;
- incremental interest expense recorded by ETP primarily due to the issuance of $1.5 billion of senior notes in May 2011 and $2.0 billion of notes in January 2012 to fund acquisitions; and
- an increase of $71 million for the Parent Company primarily related to the Parent Company's $2.0 billion Senior Secured Term Loan which was used to fund a portion of the cash consideration for the Southern Union Merger; partially offset by
- a reduction of interest due to ETP's repurchase of $750 million of its senior notes in January 2012.

Gain on Deconsolidation of Propane Business. ETP recognized a gain on deconsolidation related to the contribution of its 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 Adjustments. LIFO valuation reserve adjustments were 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.

Unrealized Gains (Losses) on Commodity Risk Management Activities. See additional discussion of the unrealized gains (losses) on commodity risk management activities included in the discussion of segment results below.

Losses on Extinguishments of Debt. ETP recognized a loss on extinguishment of debt for the year ended December 31, 2012 in connection with its repurchase of approximately $750 million in aggregate principal amount of senior notes in January 2012.

Adjusted EBITDA Related 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.

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, FEP, HPC and MEP. The 2011 amounts primarily represented our proportionate share of such amounts and do not include AmeriGas and Citrus.

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. The increase in income tax expense for the year ended December 31, 2012 compared to the same periods last year were primarily due to our acquisition of Southern Union in March 2012 which has a higher overall effective rate as Southern Union is subject to federal and state income taxes.

Segment Operating Results

Investment in ETP

	Years Ended December 31,		
	2012	2011	Change
Revenues	$ 15,702	$ 6,799	$ 8,903
Cost of products sold	12,266	4,175	8,091
Gross margin	3,436	2,624	812
Unrealized losses on commodity risk management activities	9	11	(2)
Operating expenses, excluding non-cash compensation expense	(949)	(798)	(151)
Selling, general and administrative, excluding non-cash compensation expense	(406)	(135)	(271)
Adjusted EBITDA related to discontinued operations	99	23	76
Adjusted EBITDA related to unconsolidated affiliates	480	56	424
Other, net	75	—	75
Segment Adjusted EBITDA	$ 2,744	$ 1,781	$ 963

Gross Margin. For the year ended December 31, 2012 compared to the year ended December 31, 2011, gross margin increased $812 million, primarily as a result of ETP's acquisition of Sunoco, including Sunoco Logistics and retail marketing operations, in conjunction with the Holdco Transaction in October 2012. Sunoco Logistics' gross margin was $304 million for October 5, 2012 to December 31, 2012, and retail marketing gross margin was $169 million for October 5, 2012 to December 31, 2012. In addition, NGL transportation and services gross margin increased $110 million, as the NGL transportation and services operations gross margin reflected twelve months of activity compared to only eight months of activity in 2011. Midstream gross margin increased $185 million primarily due to increased volumes and the consolidation of Southern Union's gathering and process business from March 26, 2012 to December 31, 2012. These increases were partially offset by decreases in ETP's intrastate transportation and storage gross margin of $103 million over the period, primarily due to the cessation of certain long-term transportation contracts and a continued unfavorable natural gas price environment.

Unrealized Losses on Commodity Risk Management Activities. Unrealized losses on commodity risk management activities primarily reflected the net impact from unrealized gains and losses on natural gas storage and non-storage derivatives, as well as fair value adjustments to inventory. The decrease in unrealized losses on commodity risk management activities for 2012 compared to 2011 was primarily attributable to natural gas storage inventory and related derivatives.

Operating Expenses, Excluding Non-Cash Compensation Expense. For the year ended December 31, 2012 compared to the year ended December 31, 2011, ETP's operating expense increases of $48 million were attributable to Sunoco Logistics and $119 million were attributable to ETP's retail marketing operations. As discussed above, Sunoco Logistics and the retail marketing operations were acquired in October of 2012. For the year ended December 31, 2012, the increase in operating expenses also reflects a $154 million increase in ETP's interstate transportation and storage operations primarily due to the consolidation of Southern Union beginning March 26, 2012. In addition, midstream operation expenses increased $78 million primarily due to the consolidation of Southern Union. These amounts were partially offset by a $298 million decrease in operating expense attributable to ETP's all other operations, primarily due to the contribution of ETP's propane business to AmeriGas in January 2012.

Selling, General and Administrative, Excluding Non-Cash Compensation Expense. For the year ended December 31, 2012 compared to the year ended December 31, 2011, ETP's selling, general and administrative increased $119 million due to the consolidation of Southern Union's transportation and storage operations in ETP's interstate transportation and storage operations and $46 million due to the consolidation of Southern Union's gathering and processing operations in ETP's midstream operations beginning March 26, 2012, $32 million due to the consolidation of Sunoco Logistics, and $17 million due to the consolidation of ETP's retail marketing operations. As discussed above, Sunoco Logistics and the retail marketing operations were acquired in October of 2012.

Adjusted EBITDA Related to Discontinued Operations. Amounts reflected the operations of Canyon, which was sold in October 2012, and Southern Union's distribution operations beginning March 26, 2012.

Adjusted EBITDA Related to Unconsolidated Affiliates. ETP's Adjusted EBITDA related to unconsolidated affiliates for the years ended December 31, 2012 and 2011 consisted of the following:

	Years Ended December 31,		
	2012	2011	Change
AmeriGas	$ 139	$ —	$ 139
Citrus	228	—	228
FEP	77	53	24
Other	36	3	33
Total Adjusted EBITDA related to unconsolidated affiliates	$ 480	$ 56	$ 424

Amounts reflected above include a partial period for Citrus and AmeriGas in 2012.

Other. Amounts reflected $75 million in LIFO valuation adjustments in ETP's retail marketing operations for the year ended December 31, 2012.

Investment in Regency

	Years Ended December 31,		
	2012	2011	Change
Revenues	$ 2,000	$ 1,434	$ 566
Cost of products sold	1,387	1,013	374
Gross margin	613	421	192
Unrealized gains on commodity risk management activities	(5)	—	(5)
Operating expenses, excluding non-cash compensation expense	(228)	(147)	(81)
Selling, general and administrative, excluding non-cash compensation expense	(95)	(64)	(31)
Adjusted EBITDA related to unconsolidated affiliates	222	213	9
Other, net	10	(3)	13
Segment Adjusted EBITDA	$ 517	$ 420	$ 97

Gross Margin. Regency's gross margin increased approximately $145 million for the year ended December 31, 2012 compared to the prior year due to the consolidation of SUGS beginning March 26, 2012, with the remaining of the change being attributable to increased volumes in Regency's South and West Texas and North Louisiana gathering and processing operations.

Unrealized Gains on Commodity Risk Management Activities. Regency's gains on commodity risk management activities increased primarily due to mark-to-market adjustments on its non-hedged commodity derivatives during the year ended December 31, 2012.

Operating Expenses, Excluding Non-Cash Compensation Expense. Regency's operating expenses, excluding non-cash compensation expenses, increased approximately $62 million due to the consolidation of SUGS beginning March 26, 2012, with the remaining change attributable to increased pipeline and plant operating activity in South and West Texas, increased compressor maintenance expense primarily due to increases in maintenance and materials costs, and increases in ad valorem taxes related to organic growth projects.

Selling, General and Administrative, Excluding Non-Cash Compensation Expense. Regency's selling, general and administrative expenses, excluding non-cash compensation expense, increased for the year ended December 31, 2012 compared to the prior year primarily due to the consolidation of SUGS beginning March 26, 2012, which was partially offset by a decrease of approximately $4 million as a result of lower professional fees and lower rent expense.

Adjusted EBITDA Related to Unconsolidated Affiliates. Regency's adjusted EBITDA related to unconsolidated affiliates increased for the year ended December 31, 2012 compared to the prior year primarily due to the impact from Lone Star, which was formed in May 2011.

Other. Regency's other increased primarily as the result of recognition of a one-time producer payment received in March 2012 related to an assignment of certain contracts.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Parent Company Only

The Parent Company's principal sources of cash flow are derived from its direct and indirect investments in the limited partner and general partner interests in ETP and Regency. Effective with the Parent Company's acquisition of 100% of Trunkline LNG on February 19, 2014, the Parent Company will also generate cash flows through Trunkline LNG's wholly-owned subsidiaries. The amount of cash that ETP and Regency distribute to their respective partners, including the Parent Company, each quarter is based on earnings from their respective business activities and the amount of available cash, as discussed below. In connection with certain transactions we have relinquished a portion of our incentive distributions to be received from ETP and Regency in future quarters, see additional discussion under "Cash Distributions."

The Parent Company's primary cash requirements are for general and administrative expenses, debt service requirements and distributions to its partners and holders of the Preferred Units. The Parent Company currently expects to fund its short-term needs for such items with cash flows from its direct and indirect investments in ETP, Regency and Holdco. The Parent Company distributes its available cash remaining after satisfaction of the aforementioned cash requirements to its Unitholders on a quarterly basis.

We expect ETP, Regency and Trunkline LNG and their respective subsidiaries to utilize their resources, along with cash from their operations, to fund their announced growth capital expenditures and working capital needs; however, the Parent Company may issue debt or equity securities from time to time, as we deem prudent to provide liquidity for new capital projects of our subsidiaries or for other partnership purposes.

ETP

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

ETP currently expects capital expenditures in 2014 to be within the following ranges:

	Growth		Maintenance	
	Low	High	Low	High
Intrastate transportation and storage	$ 30	$ 40	$ 25	$ 30
Interstate transportation and storage	20	30	115	135
Midstream	275	300	10	15
NGL transportation and services(1)	300	330	20	25
Investment in Sunoco Logistics	1,250	1,350	65	75
Retail Marketing	125	155	50	60
All other (including eliminations)	60	80	10	15
Total projected capital expenditures	$ 2,060	$ 2,285	$ 295	$ 355

(1) ETP expects to receive capital contributions from Regency related to their 30% share of Lone Star of between $75 million and $100 million.

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

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

As of December 31, 2013, in addition to $549 million of cash on hand, ETP had available capacity under its revolving credit facilities of $2.34 billion. Based on ETP's current estimates, it expects to utilize capacity under the ETP Credit Facility, along with cash from operations, to fund its announced growth capital expenditures and working capital needs for the next 12 months; however, ETP may issue debt or equity securities prior to that time as it deems 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 $1.50 billion credit facility. At December 31, 2013, Sunoco Logistics had available borrowing capacity of $1.30 billion under its revolving credit facility. 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 supplements its cash flows from operations with proceeds from debt and equity financing activities.

Regency

Regency expects its sources of liquidity to include: cash generated from operations and occasional asset sales; borrowings under the Regency Credit Facility; distributions received from unconsolidated affiliates; debt offerings; and issuance of additional partnership units.

In 2014, Regency expects to invest $540 million in growth capital expenditures, of which $230 million is expected to be invested in organic growth projects in the gathering and processing operations; $110 million is expected to be invested in Regency's portion of growth capital expenditures in its NGL services operations; and $200 million is expected to be invested in growth capital expenditures in its contract services operations. In addition, Regency expects to invest $60 million in maintenance capital expenditures in 2014, including its proportionate share related to joint ventures.

Regency may revise the timing of these expenditures as necessary to adapt to economic conditions. Regency expects to fund its growth capital expenditures with borrowings under its revolving credit facility and a combination of debt and equity issuances.

Cash Flows

Our cash flows may change in the future due to a number of factors, some of which we cannot control. These factors include regulatory changes, the price of our subsidiaries' 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 acquisition of assets, while changes in non-cash unit-based compensation expense resulted 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 ETP has 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 purchases and sales of inventories, and the timing of advances and deposits received from customers.

Following is a summary of operating activities by period:

Year Ended December 31, 2013

Cash provided by operating activities in 2013 was $2.42 billion and net income was $315 million. The difference between net income and cash provided by operating activities in 2013 consisted of net non-cash items totaling $1.94 billion and changes in operating assets and liabilities of $149 million. The non-cash activity consisted primarily of depreciation and amortization of $1.31 billion, goodwill impairment of $689 million, deferred income taxes of $43 million, losses on extinguishments of debt of $162 million and non-cash compensation expense of $61 million.

Year Ended December 31, 2012

Cash provided by operating activities in 2012 was $1.08 billion and net income was $1.27 billion. The difference between net income and cash provided by operating activities in 2012 consisted of net non-cash items totaling $85 million and changes in operating assets and liabilities of $551 million. The non-cash activity consisted primarily of a gain on the deconsolidation of ETP's propane business of $1.06 billion, which was offset by depreciation and amortization of $871 million, losses on extinguishments of debt of $123 million and non-cash compensation expense of $47 million.

Year Ended December 31, 2011

Cash provided by operating activities in 2011 was $1.38 billion and net income was $528 million. The difference between net income and cash provided by operating activities in 2011 consisted of non-cash items totaling $566 million and changes in operating assets and liabilities of $158 million. The non-cash activity consisted primarily of depreciation and amortization of $586 million and non-cash compensation expense of $42 million.

Investing Activities

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

Following is a summary of investing activities by period:

Year Ended December 31, 2013

Cash used in investing activities in 2013 of $2.35 billion was comprised primarily of capital expenditures of $3.51 billion (excluding the allowance for equity funds used during construction). ETP invested $2.11 billion for growth capital expenditures and $343 million for maintenance capital expenditures during 2013. Regency invested $948 million for growth capital expenditures and $48 million for maintenance capital expenditures during 2013. These expenditures were partially offset by $1.01 billion and $346 million of cash received from the sale of the MGE and NEG assets and the sale of AmeriGas common units, respectively. In addition, ETP paid net cash of $405 million for acquisitions.

Year Ended December 31, 2012

Cash used in investing activities in 2012 of $4.20 billion was comprised primarily of capital expenditures of $3.27 billion (excluding the allowance for equity funds used during construction). ETP invested $2.74 billion for growth capital expenditures and $313 million for maintenance capital expenditures during 2012. Regency invested $945 million for growth capital expenditures and $58 million for maintenance capital during 2012 (including amounts related to SUGS). Cash paid for the acquisition of Southern Union was $2.97 billion and ETP received $1.44 billion in proceeds from the contribution of propane.

Year Ended December 31, 2011

Cash used in investing activities in 2011 of $3.87 billion was comprised primarily of capital expenditures of $1.81 billion (excluding the allowance for equity funds used during construction). ETP invested $1.35 billion for growth capital expenditures and $134 million for maintenance capital expenditures during 2011. Regency invested $354 million for growth capital expenditures and $22 million for maintenance capital during 2011. In addition, our subsidiaries paid cash for acquisitions of $1.97 billion, which primarily consisted of the acquisition of Lone Star and made net advances to joint ventures of $150 million.

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 ETP's and Regency's acquisitions and growth capital expenditures. Distributions increase between the periods based on increases in the number of common units outstanding or increases in the distribution rate.

Following is a summary of financing activities by period:

Year Ended December 31, 2013

Cash provided by financing activities was $146 million in 2013. We had a consolidated increase in our debt level of $983 million, primarily due to ETP's issuance of $1.25 billion and $1.50 billion in aggregate principal amount of senior notes in January 2013 and September 2013, respectively, and Sunoco Logistics' issuance of $700 million in aggregate principal amount of senior notes in January 2013 (see Note 6 to our consolidated financial statements). Our subsidiaries also received $1.76 billion in proceeds from common unit offerings, which consisted of $1.61 billion from the issuance of ETP Common Units and $149 million from the issuance of Regency Common Units. We paid distributions to partners of $733 million, and our subsidiaries paid $1.43 billion on limited partner interests other than those held by the Parent Company. We also paid $340 million to redeem our Preferred Units.

Year Ended December 31, 2012

Cash provided by financing activities was $3.36 billion in 2012. We had a consolidated increase in our debt level of $4.02 billion, which primarily consisted of borrowings to fund our acquisitions of Southern Union and Sunoco. Our subsidiaries also received $1.10 billion in proceeds from common unit offerings, which consisted of $791 million from the issuance of ETP Common Units and $312 million from the issuance of Regency Common Units. We paid distributions to partners of $666 million and $24 million to the holders of our Preferred Units. In addition, our subsidiaries paid $1.02 billion on limited partner interests other than those held by the Parent Company.

Year Ended December 31, 2011

Cash provided by financing activities was $2.54 billion in 2011. ETP received $1.47 billion in net proceeds from offerings of ETP Common Units, including $96 million under its equity distribution program (see Note 8 to our consolidated financial statements). In addition, Regency received $436 million in net proceeds from offerings of Regency Common Units. We had a consolidated net increase in our debt level of $2.00 billion and paid distributions of $526 million to our common unitholders and $24 million to the holders of our Preferred Units. In addition, ETP paid distributions of $562 million on limited partner interests other than those held by the Parent Company and Regency paid $217 million on limited partner interests other than those held by the Parent Company. These distributions are reflected as distributions to noncontrolling interests on our consolidated statements of cash flows.

Description of Indebtedness

Our outstanding consolidated indebtedness at December 31, 2013 and 2012 was as follows:

	December 31,	
	2013	2012
Parent Company Indebtedness:		
ETE Senior Notes	$ 1,637	$ 1,800
ETE Senior Secured Term Loan	—	2,000
ETE Senior Secured Revolving Credit Facility	1,171	60
Subsidiary Indebtedness:		
ETP Senior Notes	11,182	7,692
Regency Senior Notes	2,800	1,962
Transwestern Senior Unsecured Notes	870	870
Southern Union Senior Notes	169	1,260
Panhandle Senior Notes	916	1,621
Sunoco Senior Notes	965	965
Sunoco Logistics Senior Notes	2,150	1,450
Revolving Credit Facilities:		
ETP $2.5 billion Revolving Credit Facility due October 27, 2016	65	1,395
Regency $1.2 billion Revolving Credit Facility due May 21, 2018	510	192
Southern Union $700 million Revolving Credit Facility due May 20, 2016	—	210
Sunoco Logistics $200 million Revolving Credit Facility due August 21, 2014	—	26
Sunoco Logistics $35 million Revolving Credit Facility due April 30, 2015	35	20
Sunoco Logistics $350 million Revolving Credit Facility due August 22, 2016	—	93
Sunoco Logistics $1.50 billion Revolving Credit Facility due November 1, 2018	200	—
Other long-term debt	228	51
Unamortized premiums and fair value adjustments, net	301	386
Total debt	23,199	22,053
Less: current maturities	637	613
Long-term debt, less current maturities	$ 22,562	$ 21,440

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

Parent Company Indebtedness

On December 2, 2013, the Parent Company completed a public offering of $450 million aggregate principal amount of its 5.875% Senior Notes due 2024. The Parent Company used net proceeds from this offering, together with a portion of the net proceeds from the Revolver Credit Agreement and the ETE Term Loan Facility, discussed below, to fund the Parent Company's tender offer for a portion of its 7.500% Senior Notes due 2020 (together with the 5.875% Senior Notes due 2024, the "ETE Senior Notes").

The ETE Senior Notes are the Parent Company's senior obligations, ranking equally in right of payment with our other existing and future unsubordinated debt and senior to any of its future subordinated debt. The Parent Company's obligations under the ETE Senior Notes are secured on a first-priority basis with its obligations under the Revolver Credit Agreement and the ETE Term Loan Facility, by a lien on substantially all of the Parent Company's and certain of its subsidiaries' tangible and intangible assets, subject to certain exceptions and permitted liens. The ETE Senior Notes are not guaranteed by any of the Parent Company's subsidiaries.

The covenants related to the ETE Senior Notes include a limitation on liens, a limitation on transactions with affiliates, a restriction on sale-leaseback transactions and limitations on mergers and sales of all or substantially all of the Parent Company's assets.

ETE Term Loan Facility

On December 2, 2013, the Parent Company entered into a Senior Secured Term Loan Agreement (the "ETE Term Credit Agreement"), which has a scheduled maturity date of December 2, 2019, with an option to extend the term subject to the terms and conditions set forth therein. Pursuant to the ETE Term Credit Agreement, the lenders have provided senior secured financing in an aggregate principal amount of $1.0 billion (the "ETE Term Loan Facility"). The Parent Company shall not be required to make any amortization payments with respect to the term loans under the Term Credit Agreement. Under certain circumstances, the Partnership is required to repay the term loan in connection with dispositions of (a) incentive distribution rights in ETP or Regency, (b) general partnership interests in Regency or (c) equity interests of any Person which owns, directly or indirectly, incentive distribution rights in ETP or Regency or general partnership interests in Regency, in each case, yielding net proceeds in excess of $50 million.

Under the Term Credit Agreement, the obligations of the Parent Company are secured by a lien on substantially all of the Parent Company's and certain of its subsidiaries' tangible and intangible assets, subject to certain exceptions and permitted liens. The ETE Term Loan Facility initially is not guaranteed by any of the Parent Company's subsidiaries.

Interest accrues on advances at a LIBOR rate or a base rate plus an applicable margin based on the election of the Parent Company for each interest period. The applicable margin for LIBOR rate loans is 2.50% and the applicable margin for base rate loans is 1.50%. Proceeds of the borrowings under the Term Credit Agreement were used to partially fund a tender offer for ETE Senior Notes completed in December 2013, to repay amounts outstanding under the Parent Company's existing term loan credit facility, and to pay transaction fees and expenses related to the tender offer, the ETE Term Loan Facility and other transactions incidental thereto.

ETE Revolving Credit Facility

On December 2, 2013, the Parent Company entered into a credit agreement (the "Revolving Credit Agreement"), which has a scheduled maturity date of December 2, 2018, with an option for the Partnership to extend the term subject to the terms and conditions set forth therein.

Pursuant to the Revolver Credit Agreement, the lenders have committed to provide advances up to an aggregate principal amount of $600 million at any one time outstanding (the "ETE Revolving Credit Facility"), and the Parent Company has the option to request increases in the aggregate commitments provided that the aggregate commitments never exceed $1.0 billion. In February 2014, the Partnership increased the capacity on the ETE Revolving Credit Facility to $800 million and expects to utilize the additional capacity to fund the purchase of $400 million of Regency common units in connection with Regency's pending Eagle Rock acquisition.

As part of the aggregate commitments under the facility, the Revolver Credit Agreement provides for letters of credit to be issued at the request of the Parent Company in an aggregate amount not to exceed a $150 million sublimit.

Under the Revolver Credit Agreement, the obligations of the Parent Company are secured by a lien on substantially all of the Parent Company's and certain of its subsidiaries' tangible and intangible assets. Borrowings under the Revolver Credit Agreement are not guaranteed by any of the Parent Company's subsidiaries.

Interest accrues on advances at a LIBOR rate or a base rate plus an applicable margin based on the election of the Parent Company for each interest period. The issuing fees for all letters of credit are also based on an applicable margin. The applicable margin used in connection with interest rates and fees is based on the then applicable leverage ratio of the Parent Company. The applicable margin for LIBOR rate loans and letter of credit fees ranges from 1.75% to 2.50% and the applicable margin for base rate loans ranges from 0.75% to 1.50%. The Parent Company will also pay a fee based on its leverage ratio on the actual daily unused amount of the aggregate commitments.

Subsidiary Indebtedness

ETP January 2013 Senior Notes Offering

In January 2013, ETP issued $800 million aggregate principal amount of 3.6% Senior Notes due February 2023 and $450 million aggregate principal amount of 5.15% Senior Notes due February 2043. ETP used the net proceeds of $1.24 billion from the offering to repay borrowings outstanding under the ETP Credit Facility and for general partnership purposes.

Sunoco Logistics 2013 Senior Notes Offering

In January 2013, Sunoco Logistics issued $350 million aggregate principal amount of 3.45% Senior Notes due January 2023 and $350 million aggregate principal amount of 4.95% Senior Notes due January 2043. Sunoco Logistics' used the net proceeds of $691 million from the offering to repay borrowings outstanding under the Sunoco Logistics' Credit Facilities and for general partnership purposes.

ETP September 2013 Senior Notes Offering

In September 2013, ETP issued $700 million aggregate principal amount of 4.15% Senior Notes due October 2020, $350 million aggregate principal amount of 4.90% Senior Notes due February 2024 and $450 million aggregate principal amount of 5.95% Senior Notes due October 2043. ETP used the net proceeds of $1.47 billion from the offering to repay $455 million in borrowings outstanding under the term loan of Panhandle's wholly-owned subsidiary, Trunkline LNG Holdings, LLC, to repay borrowings outstanding under the ETP Credit Facility and for general partnership purposes.

Note Exchange

On June 24, 2013, ETP completed the exchange of approximately $1.09 billion aggregate principal amount of Southern Union's outstanding senior notes, comprising 77% of the principal amount of the 7.6% Senior Notes due 2024, 89% of the principal amount of the 8.25% Senior Notes due 2029 and 91% of the principal amount of the Junior Subordinated Notes due 2066. These notes were exchanged for new notes issued by ETP with the same coupon rates and maturity dates. In conjunction with this transaction, Southern Union entered into intercompany notes payable to ETP, which provide for the reimbursement by Southern Union of ETP's payments under the newly issued notes.

Credit Facilities

ETP Credit Facility

The ETP Credit Facility allows for borrowings of up to $2.5 billion and expires in October 2017. The indebtedness under the ETP Credit Facility is unsecured and not guaranteed by any of ETP's subsidiaries and has equal rights to holders of ETP's 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.

ETP uses the ETP Credit Facility to provide temporary financing for its growth projects, as well as for general partnership purposes. ETP typically repays amounts outstanding under the ETP Credit Facility with proceeds from common unit offerings or long-term notes offerings. The timing of borrowings depends on ETP'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. ETP does not believe that such fluctuations indicate a significant change in its liquidity position, because it expects 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.

In November 2013, ETP amended the ETP Credit Facility to, among other things, (i) extend the maturity date for one additional year to October 2017, (ii) remove the restriction prohibiting unrestricted subsidiaries from owning debt or equity interests in ETP or any restricted subsidiaries of ETP, (iii) amend the covenant limiting fundamental changes to remove the restrictions on mergers or other consolidations of restricted subsidiaries of ETP and to permit ETP to merge with another person and not be the surviving entity provided certain requirements are met, and (iv) amend certain other provisions more specifically set forth in the amendment.

As of December 31, 2013, ETP had a balance of $65 million outstanding under the ETP Credit Facility and, the amount available for future borrowing was $2.34 billion taking into account letters of credit of $93 million. The weighted average interest rate on the total amount outstanding as of December 31, 2013 was 1.67%.

Regency Revolving Credit Facility

The Regency Credit Facility has aggregate revolving commitments of $1.20 billion, with a $300 million incremental facility. The maturity date of the Regency Credit Facility is May 21, 2018.

The outstanding balance of revolving loans under the Regency Credit Facility bears interest at LIBOR plus a margin or an alternate base rate. The alternate base rate used to calculate interest on base rate loans will be calculated using the greater of a base rate, a federal funds effective rate plus 0.50% and an adjusted one-month LIBOR rate plus 1.00%. The applicable margin ranges from 0.625% to 1.50% for base rate loans and 1.625% to 2.50% for Eurodollar loans.

Regency pays (i) a commitment fee ranging between 0.30% and 0.45% per annum for the unused portion of the revolving loan commitments; (ii) a participation fee for each revolving lender participating in letters of credit ranging between 1.625% and 2.50% per annum of the average daily amount of such lender's letter of credit exposure and; (iii) a fronting fee to the issuing bank of letters of credit equal to 0.20% per annum of the average daily amount of its letter of credit exposure. In December 2011, Regency amended its credit facility to allow for additional investments in its joint ventures.

As of December 31, 2013, Regency had a balance outstanding of $510 million under the Regency Credit Facility in revolving credit loans and approximately $14 million in letters of credit. The total amount available under the Regency Credit Facility, as of December 31, 2013, which is reduced by any letters of credit, was approximately $676 million. The weighted average interest rate on the total amount outstanding as of December 31, 2013 was 2.17%.

Southern Union Credit Facilities

Proceeds from the SUGS Contribution were used to repay borrowings under the Southern Union Credit Facility and the facility was terminated during 2013.

Sunoco Logistics Credit Facilities

In November 2013, Sunoco Logistics replaced its existing $350 million and $200 million unsecured credit facilities with a new $1.50 billion unsecured credit facility (the "$1.50 billion Credit Facility"). The $1.50 billion Credit Facility contains an accordion feature, under which the total aggregate commitment may be extended to $2.25 billion under certain conditions. Outstanding borrowings under the $350 million and $200 million credit facilities of $119 million at December 31, 2012 were repaid during the first quarter of 2013.

The $1.50 billion Credit Facility, which matures in November 2018, is available to fund Sunoco Logistics' working capital requirements, to finance acquisitions and capital projects, to pay distributions and for general partnership purposes. The $1.50 billion Credit Facility bears interest at LIBOR or the Base Rate, each plus an applicable margin. The credit facility may be prepaid at any time. Outstanding borrowings under this credit facility were $200 million at December 31, 2013.

West Texas Gulf Pipe Line Company, a subsidiary of Sunoco Logistics, has a $35 million revolving 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 $35 million at December 31, 2013.

Covenants Related to Our Credit Agreements

Covenants Related to the Parent Company

The ETE Term Loan Facility and ETE Revolving Credit Facility contain customary representations, warranties, covenants, and events of default, including a change of control event of default and limitations on incurrence of liens, new lines of business, merger, transactions with affiliates and restrictive agreements.

The ETE Term Loan Facility and ETE Revolving Credit Facility contain financial covenants as follows:

- Maximum Leverage Ratio – Consolidated Funded Debt of the Parent Company (as defined) to EBITDA (as defined in the agreements) of the Parent Company of not more than 6.0 to 1, with a permitted increase to 7 to 1 during a specified acquisition period following the close of a specified acquisition; and
- EBITDA to interest expense of not less than 1.5 to 1.

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

The credit agreement relating to the ETP Credit Facility contains covenants that limit (subject to certain exceptions) ETP's and certain of ETP'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 ETP 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.

Covenants Related to Regency Credit Agreements

The Regency Senior Notes contain various covenants that limit, among other things, Regency's ability, and the ability of certain of its subsidiaries, to:

- incur additional indebtedness;
- pay distributions on, or repurchase or redeem equity interests;
- make certain investments;
- incur liens;
- enter into certain types of transactions with affiliates; and
- sell assets, consolidate or merge with or into other companies.

If the Regency Senior Notes achieve investment grade ratings by both Moody's and S&P and no default or event of default has occurred and is continuing, Regency will no longer be subject to many of the foregoing covenants. The Regency Credit Facility contains the following financial covenants:

- Regency's consolidated EBITDA ratio for any preceding four fiscal quarter period, as defined in the credit agreement governing the Regency Credit Facility, must not exceed 5.00 to 1.
- Regency's consolidated EBITDA to consolidated interest expense, as defined in the credit agreement governing the Regency Credit Facility, must be greater than 2.50 to 1.
- Regency's consolidated senior secured leverage ratio for any preceding four fiscal quarter period, as defined in the credit agreement governing the Regency Credit Facility, must not exceed 3.25 to 1.

The Regency Credit Facility also contains various covenants that limit, among other things, the ability of Regency and RGS to:

- incur indebtedness;
- grant liens;
- enter into sale and leaseback transactions;
- make certain investments, loans and advances;
- dissolve or enter into a merger or consolidation;
- enter into asset sales or make acquisitions;
- enter into transactions with affiliates;

- prepay other indebtedness or amend organizational documents or transaction documents (as defined in the credit agreement governing the Regency Credit Facility);
- issue capital stock or create subsidiaries; or
- engage in any business other than those businesses in which it was engaged at the time of the effectiveness of the Regency Credit Facility or reasonable extensions thereof.

Covenants Related to Southern Union 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 the 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.

In addition, 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 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

Sunoco Logistics' $350 million and $200 million credit facilities contain various covenants limiting its 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 its 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 consolidated debt, excluding net unamortized fair value adjustments, to consolidated Adjusted EBITDA was 2.8 to 1 at December 31, 2013, as calculated in accordance with the credit agreements.

The $35 million credit facility 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, 2013 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 1.12 to 1 and 0.88 to 1, respectively, at December 31, 2013.

Compliance with our Covenants

We are required to assess compliance quarterly and were in compliance with all requirements, limitations, and covenants relating to ETE's and its subsidiaries' debt agreements as of December 31, 2013.

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

Contingent Residual Support Agreement – AmeriGas

In order to finance the cash portion of the purchase price of the Propane Business described in Note 6 to 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 with AmeriGas, Finance Company, AmeriGas Finance Corp. and UGI Corp., pursuant to which ETP will provide contingent, residual support of the Supported Debt.

PEPL Holdings Guarantee of Collection

In connection with the SUGS Contribution, Regency issued $600 million of 4.50% Senior Notes due 2023 (the “Regency Debt”), the proceeds of which were used by Regency to fund the cash portion of the consideration, as adjusted, and pay certain other expenses or disbursements directly related to the closing of the SUGS Contribution. In connection with the closing of the SUGS Contribution on April 30, 2013, Regency entered into an agreement with PEPL Holdings, a subsidiary of Southern Union, pursuant to which PEPL Holdings provided a guarantee of collection (on a nonrecourse basis to Southern Union) to Regency and Regency Energy Finance Corp. with respect to the payment of the principal amount of the Regency Debt through maturity in 2023. In connection with the completion of the Panhandle Merger, in which PEPL Holdings was merged with and into Panhandle, the guarantee of collection for the Regency Debt was assumed by Panhandle.

Contractual Obligations

The following table summarizes our long-term debt and other contractual obligations as of December 31, 2013:

	Payments Due by Period				
Contractual Obligations	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Long-term debt	$ 22,898	$ 812	$ 1,422	$ 3,196	$ 17,468
Interest on long-term debt[1]	15,921	1,263	2,340	2,154	10,164
Payments on derivatives	74	35	39	—	—
Purchase commitments[2]	25,704	12,389	7,883	2,175	3,257
Transportation, natural gas storage and fractionation contracts	122	33	48	37	4
Operating lease obligations	813	83	153	123	454
Distributions and redemption of preferred units of a subsidiary[3]	100	3	7	7	83
Other	246	77	89	56	24
Total[4]	$ 65,878	$ 14,695	$ 11,981	$ 7,748	$ 31,454

(1) Interest payments on long-term debt are based on the principal amount of debt obligations as of December 31, 2013. With respect to variable rate debt, the interest payments were estimated using the interest rate as of December 31, 2013. To the extent interest rates change, our contractual obligation for interest payments will change. See “Item 7A. Quantitative and Qualitative Disclosures About Market Risk” for further discussion.

(2) 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 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, 2013 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 $5.72 billion of total purchase commitments relate to production from PES.

(3) Assumes the outstanding Regency Preferred Units are redeemed for cash on September 2, 2029.

(4) Excludes net non-current deferred tax liabilities of $3.87 billion due to uncertainty of the timing of future cash flows for such liabilities.

Cash Distributions

Cash Distributions Paid by the Parent Company

Under the Parent Company Partnership Agreement, the Parent Company will distribute all of its Available Cash, as defined, within 50 days following the end of each fiscal quarter. Available cash generally means, with respect to any 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 that is necessary or appropriate to provide for future cash requirements.

Distributions paid are as follows:

Quarter Ended	Record Date	Payment Date	Rate	
Year Ended December 31, 2013	November 4, 2013	November 19, 2013	$	0.33625
	August 5, 2013	August 19, 2013		0.32750
	May 6, 2013	May 17, 2013		0.32250
	February 7, 2013	February 19, 2013		0.31750
Year Ended December 31, 2012	November 6, 2012	November 16, 2012	$	0.31250
	August 6, 2012	August 17, 2012		0.31250
	May 4, 2012	May 18, 2012		0.31250
	February 7, 2012	February 17, 2012		0.31250
Year Ended December 31, 2011	November 4, 2011	November 18, 2011	$	0.31250
	August 5, 2011	August 19, 2011		0.31250
	May 6, 2011	May 19, 2011		0.28000
	February 7, 2011	February 18, 2011		0.27000

On January 28, 2014, the Parent Company declared a cash distribution for the three months ended December 31, 2013 of $0.34625 per Common Unit, or $1.39 annualized. We paid this distribution on February 19, 2014 to Unitholders of record at the close of business on February 7, 2014.

The total amounts of distributions declared during the periods presented (all from Available Cash from the Parent Company's operating surplus and are shown in the period to which they relate) are as follows:

	Years Ended December 31,		
	2013	2012	2011
Limited Partners	$ 748	$ 703	$ 543
General Partner interest	2	1	2
Total Parent Company distributions	$ 750	$ 704	$ 545

Cash Distributions Received by the Parent Company

The Parent Company's cash available for distributions is primarily generated from its direct and indirect interests in ETP and Regency. Effective with the Parent Company's acquisition of 100% of Trunkline LNG on February 19, 2014, Trunkline LNG's wholly-owned subsidiaries also contribute to the Parent Company's cash available for distributions. Subsequent to that transaction, our interests in ETP and Regency consist of 100% of the respective general partner interests and IDRs, as well as the following:

	ETP	Regency
Units held by wholly-owned subsidiaries:		
Common units	30.8 (1)	26.3
ETP Class H units	50.2	—
Units held by less than wholly-owned subsidiaries:		
Common units	—	31.4
Regency Class F units	—	6.3

(1) On February 19, 2014, ETE closed on its acquisition of TLNG from ETP in exchange for the redemption by ETP of 18.71 million ETP common units held by ETE. This amount represents the ETP common units owned through wholly-owned subsidiaries subsequent to the transaction.

As the holder of ETP's and Regency's IDRs, the Parent Company is entitled to an increasing share of ETP's and Regency's total distributions above certain target levels. The following table summarizes the target levels (as a percentage of total distributions on common units, IDRs and the general partner interest). The percentage reflected in the table includes only the percentage related to the IDRs and excludes distributions to which the Parent Company would also be entitled through its direct or indirect ownership of (i) ETP's general partner interest, Class H units and a portion of the outstanding ETP common units and (ii) Regency's general partner interest and a portion of the outstanding Regency common units.

	Percentage of Total Distributions to IDRs	Quarterly Distribution Rate Target Amounts	
		ETP	Regency
Minimum quarterly distribution	—%	$0.25	$0.35
First target distribution	—%	$0.25 to $0.275	$0.35 to $0.4025
Second target distribution	13%	$0.275 to $0.3175	$0.4025 to $0.4375
Third target distribution	23%	$0.3175 to $0.4125	$0.4375 to $0.5250
Fourth target distribution	48%	Above $0.4125	Above $0.5250

The total amount of distributions the Parent Company received from ETP and Regency relating to its limited partner interests, general partner interest and incentive distributions (shown in the period to which they relate) for the periods ended as noted below is as follows:

	Years Ended December 31,		
	2013	2012	2011
Distributions from ETP:			
Limited Partners	$ 268	$ 180	$ 180
Class H Units held by ETE Holdings	105	—	—
General Partner interest	20	20	20
Incentive distributions	701	529	422
Incentive distribution relinquishments related to previous transactions	(199)	(90)	—
Total distributions from ETP	895	639	622
Distributions from Regency:			
Limited Partners	48	48	48
General Partner interest	5	5	5
Incentive distributions	12	8	6
Incentive distribution relinquishments related to previous transaction	(3)	—	—
Total distributions from Regency	62	61	59
Total distributions received from subsidiaries	$ 957	$ 700	$ 681

The distributions reflected above for the year ended December 31, 2013 reflect incentive distribution reductions totaling $199 million, which includes four quarters of incentive distribution relinquishments related to the Citrus Merger, four quarters of incentive distribution relinquishments related to the Holdco Transaction and two quarters of incentive distribution relinquishments related to the Holdco Acquisition. The distributions reflected above for the year ended December 31, 2012 reflect incentive distribution reductions totaling $90 million, which includes four quarters of incentive distribution relinquishments related to the Citrus Merger and two quarters of incentive distribution relinquishments related to the Holdco Transaction.

Following are incentive distributions ETE has agreed to relinquish to ETP:

- In conjunction with ETP's Citrus Merger, ETE agreed to relinquish its rights to $220 million of incentive distributions from ETP that ETE would otherwise be entitled to receive over 16 consecutive quarters beginning with the distribution paid on May 15, 2012.
- In conjunction with the Holdco Transaction in October 2012, 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.
- As discussed in Note 3, in connection with the Holdco Acquisition on April 30, 2013, ETE also agreed to relinquish incentive distributions on the newly issued Common Units for the first eight consecutive quarters beginning with the distribution paid on August 14, 2013, and 50% of the incentive distributions for the following eight consecutive quarters.
- In conjunction with Southern Union's contributions of SUGS to Regency, ETE agreed to relinquish incentive distributions on the 31.4 million Regency Common Units issued for twenty-four months subsequent to the transaction closing.

In addition, the incremental distributions on the Class H Units were intended to offset a portion of the incentive distribution subsidies previously granted by ETE to ETP. In connection with the issuance of the ETP Class H Units, ETE and ETP also agreed to certain adjustments to the incremental distributions on the ETP Class H Units in order to ensure that the net impact of the incentive distribution subsidies (a portion of which is variable) and the incremental distributions on the ETP Class H Units are fixed amounts for each quarter for which the incentive distribution subsidies and incremental distributions on the ETP Class H Units are in effect.

In connection with the transfer of Trunkline LNG on February 19, 2014, ETE agreed to relinquish incentive distributions of $50 million, $50 million, $45 million, and $35 million during the years ending December 31, 2016, 2017, 2018 and 2019, respectively.

Following is a summary of the net amounts by which these incentive distribution relinquishments and incremental distributions on Class H Units would reduce the total distributions that would potentially be made to ETE in future quarters:

	Quarters Ending				
	March 31	June 30	September 30	December 31	Total Year
2014	$ 26.5	$ 26.5	$ 26.5	$ 26.5	$ 106.0
2015	12.5	12.5	13.0	13.0	51.0
2016	18.0	18.0	18.0	18.0	72.0
2017	12.5	12.5	12.5	12.5	50.0
2018	11.25	11.25	11.25	11.25	45.0
2019	8.75	8.75	8.75	8.75	35.0

Cash Distributions Paid by ETP

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

Distributions paid by ETP are summarized as follows:

	Record Date	Payment Date	Rate
Year Ended December 31, 2013	November 4, 2013	November 14, 2013	$ 0.90500
	August 5, 2013	August 14, 2013	0.89375
	May 6, 2013	May 15, 2013	0.89375
	February 7, 2013	February 14, 2013	0.89375
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

On January 28, 2014, ETP declared a cash distribution for the three months ended December 31, 2013 of $0.9200 per ETP Common Unit, or $3.68 annualized. ETP paid this distribution on February 14, 2014 to ETP Unitholders of record at the close of business on February 7, 2014.

The total amounts of distributions declared during the periods presented (all from Available Cash from ETP's operating surplus and are shown in the period to which they relate) are as follows (in millions):

	Years Ended December 31,		
	2013	2012	2011
Limited Partners:			
Common Units	$ 1,273	$ 963	$ 762
Class H Units	105	—	—
General Partner interest	20	20	20
IDRs	701	529	422
IDR relinquishments related to previous transactions [1]	(199)	(90)	—
Total ETP distributions	$ 1,900	$ 1,422	$ 1,204

[1] In connection with certain prior transactions, the Parent Company has agreed to relinquish its rights to specified amounts of distribution payments for a limited period of time. See discussion above under "Cash Distributions Received by the Parent Company."

Cash Distributions Paid by Sunoco Logistics

Sunoco Logistics is required by its partnership agreement to distribute all cash on hand at the end of each quarter, less appropriate reserves determined by its general partner.

Following are distributions declared and/or paid by Sunoco Logistics:

Quarter Ended	Record Date	Payment Date	Rate
September 30, 2013	November 8, 2013	November 14, 2013	$ 0.63000
June 30, 2013	August 8, 2013	August 14, 2013	0.60000
March 31, 2013	May 9, 2013	May 15, 2013	0.57250
December 31, 2012	February 8, 2013	February 14, 2013	0.54500

On January 29, 2014, Sunoco Logistics declared a cash distribution for the three months ended December 31, 2013 of $0.6625 per common unit, or $2.65 annualized. Sunoco Logistics paid this distribution on February 14, 2014 to unitholders of record at the close of business on February 10, 2014.

The total amounts of Sunoco Logistics distributions declared during the period presented were as follows (all from Available Cash from Sunoco Logistics' operating surplus and are shown in the period with respect to which they relate):

	Year Ended December 31, 2013
Limited Partners	$ 255
General Partner interest	4
Incentive distributions	118
Total distributions declared	$ 377

On January 24, 2013, Sunoco Logistics declared a cash distribution for the three months ended December 31, 2012 of $0.5450 per common unit, or $2.18 annualized. The $80 million distribution, including $23 million to the general partner, was paid on February 14, 2013 to unitholders of record at the close of business on February 8, 2013.

Cash Distributions Paid by Regency

Regency's partnership agreement requires that Regency distribute all of its Available Cash to its Unitholders and its General Partner within 45 days after the end of each quarter to unitholders of record on the applicable record date, as determined by the general partner. The term Available Cash generally consists of all cash and cash equivalents on hand at the end of that quarter less the amount of cash reserves established by the general partner to: (i) provide for the proper conduct of the Partnership's business; (ii) comply with applicable law, any debt instruments or other agreements; or (iii) provide funds for distributions to the unitholders and to the General Partner for any one or more of the next four quarters and plus, all cash on hand on that date of determination of available cash for the quarter resulting from working capital borrowings made after the end of the quarter for which the determination is being made.

Distributions paid by Regency since the date of acquisition are summarized as follows:

Quarter Ended	Record Date	Payment Date	Rate
September 30, 2013	November 4, 2013	November 14, 2013	$ 0.470
June 30, 2013	August 5, 2013	August 14, 2013	0.465
March 31, 2013	May 6, 2013	May 13, 2013	0.460
December 31, 2012	February 7, 2013	February 14, 2013	0.460
September 30, 2012	November 6, 2012	November 14, 2012	$ 0.460
June 30, 2012	August 6, 2012	August 14, 2012	0.460
March 31, 2012	May 7, 2012	May 14, 2012	0.460
December 31, 2011	February 6, 2012	February 13, 2012	0.460
September 30, 2011	November 7, 2011	November 14, 2011	$ 0.455
June 30, 2011	August 5, 2011	August 12, 2011	0.450
March 31, 2011	May 6, 2011	May 13, 2011	0.445
December 31, 2010	February 7, 2011	February 14, 2011	0.445

On January 28, 2014, Regency declared a cash distribution for the three months ended December 31, 2013 of $0.475 per Regency Common Unit, or $1.90 annualized. Regency paid this distribution on February 14, 2014 to Regency Unitholders of record at the close of business on February 7, 2014.

The total amounts of Regency distributions declared since the date of acquisition (all from Regency's operating surplus and are shown in the period with respect to which they relate) are as follows:

	Years Ended December 31,	
	2013	2012
Limited Partners	$ 390	$ 314
General Partner Interest	5	5
Incentive Distribution Rights	12	8
IDR relinquishments related to previous transactions [1]	(3)	—
Total Regency distributions	$ 407	$ 327

(1) In connection with certain prior transactions, the Parent Company has agreed to relinquish its rights to specified amounts of distribution payments for a limited period of time. See discussion above under "Cash Distributions Received by the Parent Company."

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 on or before their adoption (when early adoption is permitted), 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 operations 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, 2013 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.

The results of ETP's intrastate transportation and storage and interstate transportation operations are determined primarily by the amount of capacity ETP's customers reserve as well as the actual volume of natural gas that flows through the transportation pipelines. Under transportation contracts, ETP 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.

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

In addition, ETP's intrastate transportation and storage operations generate revenues and margin from fees charged for storing customers' working natural gas in our storage facilities. ETP also engages in natural gas storage transactions in which ETP seeks to find and profit from pricing differences that occur over time utilizing the Bammel storage reservoir. ETP purchases physical natural gas and then sells financial contracts at a price sufficient to cover ETP's carrying costs and provide for a gross profit margin. ETP expects 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, ETP 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 ETP's midstream operations are determined primarily by the volumes of natural gas gathered, compressed, treated, processed, purchased and sold through ETP's pipeline and gathering systems and the level of natural gas and NGL prices. ETP generates midstream revenues and gross margins principally under fee-based or other arrangements in which ETP receives a fee for natural gas gathering, compressing, treating or processing services. The revenue earned from these arrangements is directly related to the volume of natural gas that flows through ETP's systems and is not directly dependent on commodity prices.

ETP also utilizes other types of arrangements in ETP's midstream operations, 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 ETP gathers natural gas from the producer, processes the natural gas and sells the resulting NGLs to third parties at market prices. In many cases, ETP provides services under contracts that contain a combination of more than one of the arrangements described above. The terms of ETP's contracts vary based on gas quality conditions, the competitive environment at the time the contracts are signed and customer requirements. ETP's 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.

ETP conducts marketing activities in which ETP markets the natural gas that flows through ETP's assets, referred to as on-system gas. ETP also attracts other customers by marketing volumes of natural gas that do not move through ETP's assets, referred to as off-system gas. For both on-system and off-system gas, ETP purchases natural gas from natural gas producers and other supply points and sells 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.

ETP has a risk management policy that provides for oversight over ETP's marketing activities. These activities are monitored independently by ETP's risk management function and must take place within predefined limits and authorizations. As a result of ETP's 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. ETP attempts 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 ETP's risk management policy.

ETP injects and holds 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. ETP uses financial derivatives to hedge the natural gas held in connection with these arbitrage opportunities. At the inception of the hedge, ETP locks 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 ETP designates the related financial contract as a fair value hedge for accounting purposes, ETP values the hedged natural gas inventory at current spot market prices along with the financial derivative ETP uses 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, ETP will record unrealized gains or lower unrealized losses. If the spread widens, ETP will record unrealized losses or lower unrealized gains. Typically, as ETP enters the winter months, the spread converges so that ETP recognizes in earnings the original locked in spread, either through mark-to-market or the physical withdrawal of natural gas.

ETP's 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 ETP's 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.

Terminalling and storage revenues are recognized at the time the services are provided. Pipeline revenues are recognized upon delivery of the barrels to the location designated by the shipper. Crude oil acquisition and marketing revenues, as well as refined product marketing revenues, are recognized when title to the product is transferred to the customer. Revenues are not recognized for crude oil exchange transactions, which are entered into primarily to acquire crude oil of a desired quality or to reduce transportation costs by taking delivery closer to end markets. Any net differential for exchange transactions is recorded as an adjustment of inventory costs in the purchases component of cost of products sold and operating expenses in the statements of operations.

ETP's retail marketing operations sell gasoline and diesel in addition to a broad mix of merchandise such as groceries, fast foods and beverages at its convenience stores. In addition, some of Sunoco's retail outlets provide a variety of car care services. Revenues related to the sale of products are recognized when title passes, while service revenues are recognized when services are provided. Title passage generally occurs when products are shipped or delivered in accordance with the terms of the respective sales agreements. In addition, revenues are not recognized until sales prices are fixed or determinable and collectability is reasonably assured.

Regency earns revenue from (i) domestic sales of natural gas, NGLs and condensate, (ii) natural gas gathering, processing and transportation, (iii) contract compression services and (iv) contract treating services. Revenue associated with sales of natural gas, NGLs and condensate are recognized when title passes to the customer, which is when the risk of ownership passes to the purchaser and physical delivery occurs. Revenue associated with transportation and processing fees are recognized when the service is provided. For contract compression services, revenue is recognized when the service is performed. For gathering and processing services, Regency receives either fees or commodities from natural gas producers depending on the type of contract. Commodities received are in turn sold and recognized as revenue in accordance with the criteria outlined above. Under the percent-of-proceeds contract type, Regency is paid for its services by keeping a percentage of the NGLs produced and a percentage of the residue gas resulting from processing the natural gas. Under the percentage-of-index contract type, Regency earns revenue by purchasing wellhead natural gas at a percentage of the index price and selling processed natural gas at a price approximating the index price and NGLs to third parties. Regency generally reports revenue gross when it acts as the principal, takes title to the product, and incurs the risks and rewards of ownership. Revenue for fee-based arrangements is presented net because Regency takes the role of an agent for the producers. Allowance for doubtful accounts is determined based on historical write-off experience and specific identification.

Regulatory Assets and Liabilities. Certain of our subsidiaries are subject to regulation by certain state and federal authorities and have accounting policies that conform to FASB Accounting Standards Codification ("ASC") Topic 980, *Regulated Operations*, which is in accordance with the accounting requirements and ratemaking practices of the regulatory authorities. The application of these accounting policies allows certain of our regulated entities 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. ETP and Regency utilize various exchange-traded and over-the-counter commodity financial instrument contracts to limit their exposure to margin fluctuations in natural gas, NGL and refined products. These contracts consist primarily of commodity futures and swaps. In addition, prior to ETP's contribution of its retail propane activities to AmeriGas, ETP used derivatives to limit its exposure to propane market prices.

If ETP or Regency 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 ETP or Regency designate a hedging relationship as a fair value hedge, they record the changes in fair value of the hedged asset or liability in cost of products sold in the 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.

ETP and Regency 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, interest rate derivatives, the Preferred Units and embedded derivatives in the Regency Preferred Units 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 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 utilizes significant unobservable inputs. Level 3 inputs are unobservable. Derivatives related to the Regency Preferred Units are valued using a binomial lattice model. The market inputs utilized in the model include credit spread, probabilities of the occurrence of certain events, common unit price, dividend yield, and expected volatility, and are considered Level 3. The fair value of the Preferred Units as of December 31, 2012 was based predominantly on an income approach model and is also considered

Level 3 as of December 31, 2012. See further information on our fair value assets and liabilities in Note 2 of our consolidated financial statements.

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, 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 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.

During the fourth quarter of 2013, we performed a goodwill impairment test on our Trunkline LNG reporting unit. In accordance with GAAP, we performed step one of the goodwill impairment test and determined that the estimated fair value of the Trunkline LNG reporting unit was less than its carrying amount primarily due to changes related to (i) the structure and capitalization of the planned LNG export project at Trunkline LNG's Lake Charles facility, (ii) an analysis of current macroeconomic factors, including global natural gas prices and relative spreads, as of the date of our assessment, (iii) judgments regarding the prospect of obtaining regulatory approval for a proposed LNG export project and the uncertainty associated with the timing of such approvals, and (iv) changes in assumptions related to potential future revenues from the import facility and the proposed export facility. An assessment of these factors in the fourth quarter of 2013 led to a conclusion that the estimated fair value of the Trunkline LNG reporting unit was less than its carrying amount. We then applied the second step in the goodwill impairment test, allocating the estimated fair value of the reporting unit among all of the assets and liabilities of the reporting unit in a hypothetical purchase price allocation. The assets and liabilities of the reporting unit had recently been measured at fair value in 2012 as a result of the acquisition of Southern Union, and those estimated fair values had been recorded at the reporting unit through the application of "push-down" accounting. For purposes of the hypothetical purchase price allocation used in the goodwill impairment test, we estimated the fair value of the assets and liabilities of the reporting unit in a manner similar to the original purchase price allocation. In allocating value to the property, plant and equipment, we used current replacement costs adjusted for assumed depreciation. We also included the estimated fair value of working capital and identifiable intangible assets in the reporting unit. We adjusted deferred income taxes based on these estimated fair values. Based on this hypothetical purchase price allocation, estimated goodwill was $184 million, which was less than the balance of $873 million that had originally been recorded by the reporting unit through "push-down" accounting in 2012. As a result, we recorded a goodwill impairment of $689 million during the fourth quarter of 2013.

No other goodwill impairments were identified or recorded for our reporting units.

Property, Plant and Equipment. Expenditures for maintenance and repairs that do not add capacity to 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, ETP capitalizes 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 1 to 99 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 estimate 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, 2013 and 2012 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, 2013, there were no legally restricted funds for the purpose of settling AROs.

Pensions and Other Postretirement Benefit Plans. We are required to measure plan assets and benefit obligations as of its fiscal year-end balance sheet date. We recognize the changes in the funded status of our defined benefit postretirement plans through AOCI or are reflected as a regulatory asset or regulatory liability for regulated subsidiaries.

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 a 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 11 to our consolidated financial statements included in "Item 8. Financial Statements and Supplementary Date" in this report.

Environmental Remediation Activities. The Partnership'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 for known claims 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 generally reflected in the accruals on an undiscounted basis, to the extent they are probable of occurrence and reasonably estimable. ETP has established a wholly-owned captive insurance company to bear certain risks associated with environmental obligations related to certain sites that are no longer operating. The premiums paid to the captive insurance company include estimates for environmental claims that have been incurred but not reported, based on an actuarially determined fully developed claims expense estimate. In such cases, ETP accrues losses attributable to unasserted claims based on the discounted estimates that are used to develop the premiums paid to the captive insurance company.

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. ETP'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, 2013, the aggregate of the estimated maximum additional reasonably possible losses, which relate to numerous individual sites, totaled approximately $6 million. This estimate of reasonably possible losses comprises estimates for remediation activities at current logistics and retail assets and, 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 the Partnership'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 the Partnership'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 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 Partnership's consolidated financial position.

Deferred Income Taxes. ETE 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 $217 million have been included in ETE's consolidated balance sheet as of December 31, 2013. All of the deferred income tax assets except $3 million attributable to state and federal NOL benefits expire before 2032 as more fully described below. The state NOL carryforward benefits of $101 million (net of federal benefit) begin to expire in 2013 with a substantial portion expiring between 2029 and 2032. The federal NOLs of $216 million ($76 million in benefits) will expire in 2032, while the $40 million of the federal tax alternative minimum tax credit carryforwards have no expiration date. We have determined that a valuation allowance totaling $74 million (net of federal income tax effects) is required for the state NOLs at December 31, 2013 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," "could," "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 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 subsidiaries' pipelines and gathering systems;
- the level of throughput in our subsidiaries' processing and treating facilities;
- the fees our subsidiaries charge and the margins they realize for their 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;
- 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 subsidiaries' 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 subsidiaries pipelines and facilities;
- the effectiveness of risk-management policies and procedures and the ability of our subsidiaries liquids marketing counterparties to satisfy their financial commitments;
- the nonpayment or nonperformance by our subsidiaries' customers;
- regulatory, environmental, political and legal uncertainties that may affect the timing and cost of our subsidiaries' internal growth projects, such as our subsidiaries' construction of additional pipeline systems;
- risks associated with the construction of new pipelines and treating and processing facilities or additions to our subsidiaries' 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 subsidiaries' 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 our subsidiaries own less than a controlling interests, including risks related to management actions at such entities that our subsidiaries 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.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

(Tabular dollar amounts are in millions)

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

Commodity Price Risk

The tables below summarize commodity-related financial derivative instruments, fair values and the effect of an assumed hypothetical 10% change in the underlying price of the commodity as of December 31, 2013 and 2012 for ETP and Regency, including derivatives related to their respective subsidiaries.

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 portfolios 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.

Our consolidated balance sheets also reflect assets and liabilities related to commodity derivatives that have previously been de-designated as cash flow hedges or for which offsetting positions have been entered. Those amounts are not subject to change based on changes in prices.

Investment in ETP

For certain of ETP's activities, it is exposed to market risks related to the volatility of commodity prices. To manage the impact of volatility from these prices, ETP utilizes 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, ETP uses derivatives to reduce market exposure and price risk within its operations as follows:

- ETP uses derivative financial instruments in connection with its 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 its carrying costs and provide a gross profit margin. ETP also uses derivatives in its intrastate transportation and storage operations 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, ETP uses derivatives for trading purposes in these operations.
- Derivatives are utilized in ETP's midstream operations in order to mitigate price volatility in its marketing activities and manage fixed price exposure incurred from contractual obligations.
- ETP also uses derivative swap contracts to mitigate risk from price fluctuations on NGLs it retains for fees in its midstream operations.
- Sunoco Logistics uses derivative contracts as economic hedges against price changes related to its forecasted refined products and NGL purchase and sale activities.
- In all other operations, ETP utilized derivatives for trading purposes.

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

If ETP designates 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 ETP designates a hedging relationship as a fair value hedge, ETP records 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.

ETP uses futures and basis swaps, designated as fair value hedges, to hedge its natural gas inventory stored in its 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.

ETP attempts to maintain balanced positions to protect itself from the volatility in the energy commodities markets; however, net unbalanced positions can exist. Long-term physical contracts are tied to index prices. System gas, which is also tied to index prices, 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.

Sunoco Logistics manages exposures to crude oil, refined products and NGL commodity prices by monitoring inventory levels and expectations of future commodity prices when making decisions with respect to risk management and inventory carried. Sunoco Logistics' policy is to purchase only commodity products for which it has a market and to structure its sales contracts so that price fluctuations for those products do not materially affect the margin Sunoco Logistics receives. Sunoco Logistics also seeks to maintain a position that is substantially balanced within its various commodity purchase and sale activities. Sunoco Logistics may experience net unbalanced positions for short periods of time as a result of production, transportation and delivery variances, as well as logistical issues associated with inclement weather conditions. When unscheduled inventory builds or draws do occur, they are monitored and managed to a balanced position over a reasonable period of time.

	December 31, 2013			December 31, 2012		
	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 (MMBtu):						
Fixed Swaps/Futures	9,457,500	$ 3	$ 5	—	$ —	$ —
Basis Swaps IFERC/NYMEX [1]	(487,500)	1	—	(30,980,000)	(6)	—
Swings Swaps IFERC	1,937,500	1	—	—	—	—
Power (Megawatt):						
Forwards	351,050	1	1	19,650	—	1
Futures	(772,476)	—	2	(1,509,300)	(1)	1
Options — Puts	(52,800)	—	—	—	—	—
Options — Calls	103,200	—	—	1,656,400	2	1
Crude (Bbls) — Futures	103,000	—	1	—	—	—
(Non-Trading)						
Natural Gas (MMBtu):						
Basis Swaps IFERC/NYMEX	570,000	—	—	150,000	(1)	—
Swing Swaps IFERC	(9,690,000)	1	—	(83,292,500)	1	1
Fixed Swaps/Futures	(8,195,000)	13	3	27,077,500	(7)	9
Forward Physical Contracts	5,668,559	(1)	2	11,689,855	—	2
NGL (Bbls) — Forwards/Swaps	(280,000)	—	3	(30,000)	—	—
Refined Products (Bbls) — Futures	(1,133,600)	—	17	(666,000)	(3)	14
Fair Value Hedging Derivatives						
(Non-Trading)						
Natural Gas (MMBtu):						
Basis Swaps IFERC/NYMEX	(7,352,500)	—	—	(18,655,000)	(1)	—
Fixed Swaps/Futures	(50,530,000)	(11)	23	(44,272,500)	4	15
Cash Flow Hedging Derivatives						
(Non-Trading)						
Natural Gas (MMBtu):						
Basis Swaps IFERC/NYMEX	(1,825,000)	—	—	—	—	—
Fixed Swaps/Futures	(12,775,000)	(3)	6	(8,212,500)	(3)	3
NGL (Bbls) — Forwards/Swaps	(780,000)	(1)	4	(930,000)	(2)	7
Refined Products (Bbls) — Futures	—	—	—	(98,000)	—	1
Crude (Bbls) — Futures	(30,000)	—	—	—	—	—

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

Investment in Regency

Regency is a net seller of NGLs, condensate and natural gas as a result of its gathering and processing operations. The prices of these commodities are impacted by changes in the supply and demand, as well as other market forces. Regency's profitability and cash flow are affected by the inherent volatility of these commodities, which could adversely affect its ability to make distributions to its unitholders. Regency manages this commodity price exposure through an integrated strategy that includes management of its contract portfolio, matching sales prices of commodities with purchases, optimization of its portfolio by monitoring basis and other price differentials in operating areas, and the use of derivative contracts. In some cases, Regency may not be able to match pricing terms or to cover its risk to price exposure with financial hedges, and it may be exposed to commodity price risk. Speculative positions are prohibited under Regency's policy.

Regency is exposed to market risks associated with commodity prices, counterparty credit, and interest rates. Regency's management and the board of directors of Regency GP have established comprehensive risk management policies and procedures to monitor and manage these market risks. Regency GP is responsible for delegation of transaction authority levels, and the Risk Management Committee of Regency GP is responsible for the overall management of credit risk and commodity price risk, including monitoring exposure limits. Regency GP's Risk Management Committee receives regular briefings on positions and exposures, credit exposures, and overall risk management in the context of market activities.

	December 31, 2013			December 31, 2012		
	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						
(Non-Trading)						
Natural Gas (MMBtu) — Fixed Swaps/Futures	24,455,000	$ (2)	$ 10	8,395,000	$ 1	$ 3
Propane (Gallons) — Forwards/Swaps	52,122,000	(3)	6	3,318,000	1	1
NLGs (Barrels) — Forwards/Swaps	438,000	1	2	243,000	—	2
WTI Crude Oil (Barrels) — Forwards/Swaps	521,000	(1)	5	356,000	2	3

Interest Rate Risk

As of December 31, 2013, ETP had $907 million of floating rate debt outstanding, Regency had $510 million of floating rate debt outstanding under its revolving credit facilities and ETE had $1.17 billion of floating rate debt outstanding under its revolving credit facilities as of December 31, 2013. 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.

The following interest rate swaps were outstanding as of December 31, 2013 and 2012 (dollars in millions), none of which are designated as hedges for accounting purposes:

			Notional Amount Outstanding	
Entity	Term	Type[1]	December 31, 2013	December 31, 2012
ETE	March 2017	Pay a fixed rate of 1.25% and receive a floating rate	$ —	$ 500
ETP	July 2013 [2]	Forward starting to pay a fixed rate of 4.03% and receive a floating rate	—	400
ETP	July 2014 [2]	Forward starting to pay a fixed rate of 4.25% and receive a floating rate	400	400
ETP	July 2018	Pay a floating rate plus a spread of 4.17% and receive a fixed rate of 6.70%	600	600
ETP	June 2021	Pay a floating rate plus a spread of 2.17% and receive a fixed rate of 4.65%	400	—
ETP	February 2023	Pay a floating rate plus a spread of 1.32% and receive a fixed rate of 3.60%	400	—
Southern Union [3]	November 2016	Pay a fixed rate of 2.97% and receive a floating rate	—	75
Southern Union [3]	November 2021	Pay a fixed rate of 3.801% and receive a floating rate	275	450

(1) 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. During the year ended December 31, 2013, ETP settled $400 million of ETP’s forward-starting interest rate swaps that had an effective date of July 2013.

(3) In connection with the Panhandle Merger, Southern Union’s interest rate swaps outstanding were assumed by Panhandle.

During the year ended December 31, 2013, ETP settled $400 million of forward-starting interest rate swaps that had an effective date of July 2013.

A hypothetical change of 100 basis points in interest rates for these interest rate swaps would result in a change in the fair value of the interest rate derivatives and earnings (recognized in gains (losses) on interest rate derivatives) of approximately $29 million as of December 31, 2013. For ETP’s $1.4 billion of interest rate swaps whereby it pays a floating rate and receives a fixed rate, a hypothetical change of 100 basis points in interest rates would result in a net change in annual cash flow (swap settlements) of $14 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 of $3 million.

Credit Risk

Credit Risk refers to the risk that a counterparty may default on its contractual obligations resulting in a loss to the Partnership. Credit policies have been approved and implemented to govern the Partnership’s portfolio of counterparties with the objective of mitigating credit losses. These policies establish guidelines, controls and limits to manage credit risk within approved tolerances by mandating an appropriate evaluation of the financial condition of existing and potential counterparties, monitoring agency credit ratings, and by implementing credit practices that limit exposure according to the risk profiles of the counterparties. Furthermore, the Partnership may at times require collateral under certain circumstances to mitigate credit risk as necessary. We also implement the use of industry standard commercial agreements which allow for the netting of positive and negative exposures associated with transactions executed under a single commercial agreement. Additionally, we utilize master netting agreements to offset credit exposure across multiple commercial agreements with a single counterparty or affiliated group of counterparties.

The Partnership’s counterparties consist of a diverse portfolio of customers across the energy industry, including petrochemical companies, commercial and industrials, oil and gas producers, municipalities, utilities and midstream companies. Our overall exposure may be affected positively or negatively by macroeconomic or regulatory changes that could impact our counterparties to one extent or another. Currently, management does not anticipate a material adverse effect in our financial position or results of operations as a consequence of counterparty non-performance.

Regency is exposed to credit risk from its derivative counterparties. Regency does not require collateral from these counterparties as it deals primarily with financial institutions when entering into financial derivatives, and enters into master netting agreements that allow for netting of swap contract receivables and payables in the event of default by either party.

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 President and Group Chief Financial Officer and Head of Business Development of our General Partner, of the effectiveness of the design and operation of our disclosure controls and procedures (as such terms are defined in Rule 13a–15(e) and 15d–15(e) of the Exchange Act) as of the end of the period covered by this report. Based upon that evaluation, management, including the President and Group Chief Financial Officer and Head of Business Development of our General Partner, concluded that our disclosure controls and procedures were adequate and effective as of December 31, 2013.

Management's Report on Internal Control over Financial Reporting

The management of Energy Transfer Equity, 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 President and Group Chief Financial Officer and Head of Business Development of our General Partner, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in the 1992 *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO Framework").

Based on our evaluation under the COSO framework, our management concluded that our internal control over financial reporting was effective as of December 31, 2013.

Grant Thornton LLP, an independent registered public accounting firm, has audited the effectiveness of our internal control over financial reporting as of December 31, 2013, as stated in their report, which is included herein.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Partners
Energy Transfer Equity, L.P.

We have audited the internal control over financial reporting of Energy Transfer Equity, L.P. (a Delaware limited partnership) and subsidiaries (the "Partnership") as of December 31, 2013, based on criteria established in the 1992 *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.

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 provides 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, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in the 1992 *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, 2013, and our report dated February 27, 2014 expressed an unqualified opinion on those financial statements.

/s/ GRANT THORNTON LLP

Dallas, Texas
February 27, 2014

Changes in Internal Controls over Financial Reporting

There has been no change in our internal controls over financial reporting (as defined in Rules 13a–15(f) or Rule 15d–15(f)) that occurred in the three months ended December 31, 2013 that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Board of Directors

Our General Partner, LE GP, LLC, manages and directs all of our activities. The officers and directors of ETE are officers and directors of LE GP, LLC. The members of our General Partner elect our General Partner's Board of Directors. The board of directors of our General Partner has the authority to appoint our executive officers, subject to provisions in the limited liability company agreement of our General Partner. Pursuant to other authority, the board of directors of our General Partner may appoint additional management personnel to assist in the management of our operations and, in the event of the death, resignation or removal of our chief executive officer, to appoint a replacement.

As of December 31, 2013, our Board of Directors was comprised of seven persons, three of whom qualify as "independent" under the NYSE's corporate governance standards. We have determined that Messrs. Harkey, Ramsey and Turner are all "independent" under the NYSE's corporate governance standards.

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 the members of our General Partner have appointed as directors individuals with experience, skills and qualifications relevant to the business of the Parent Company, 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 that the members of our General Partner have endeavored to assemble a group of individuals with the qualities and attributes required to provide effective oversight of the Parent Company.

Risk Oversight

Our Board of Directors generally administers its risk oversight function through the board as a whole. Our President, who reports to the Board of Directors, has day-to-day risk management responsibilities. Our President 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 Parent Company'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 Parent Company's internal auditor, who reports directly to the Audit Committee, and reviews the Parent Company'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.

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

The Parent Company has filed the required certifications under Section 302 of the Sarbanes-Oxley Act of 2002 as Exhibits 31.1 to this annual report. In 2013, our President and CFO provided to the NYSE the annual CEO certification regarding our compliance with the NYSE's 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 Parent Company and our Unitholders. As a policy matter, the Conflicts Committee generally reviews any proposed related-party transaction that may be material to the Parent Company to determine if the transaction presents a conflict of interest and whether the transaction is fair and reasonable to the Parent Company. 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 Parent Company, approved by all partners of the Parent Company and not a breach by the General Partner or its Board of Directors of any duties they may owe the Parent Company or the Unitholders. These duties are limited by our Partnership Agreement (see "Risks Related to Conflicts of Interest" in Item 1A. Risk Factors in this annual report).

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 member John D. Harkey, Jr. qualified as an audit committee financial expert during 2013. A description of the qualifications of Mr. Harkey may be found elsewhere in this Item 10 under "Directors and Executive Officers of the General Partner."

The Audit Committee meets on a regularly scheduled basis with our independent accountants at least four times each year and is available to meet at their request. The Audit Committee has the authority and responsibility to review our external financial reporting, review our procedures for internal auditing and the adequacy of our internal accounting controls, consider the qualifications and independence of our independent accountants, engage and direct our independent accountants, including the letter of engagement and statement of fees relating to the scope of the annual audit work and special audit work which may be recommended or required by the independent accountants, and to engage the services of any other advisors and accountants as the Audit Committee deems advisable. The Audit Committee reviews and discusses the audited financial statements with management, discusses with our independent auditors matters required to be discussed by 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 Audit Committee has received written disclosures and the letter from Grant Thornton required by applicable requirements of the Audit Committee concerning independence and has discussed with Grant Thornton that firm's independence. The Audit Committee recommended to the Board that the audited financial statements of ETE be included in ETE's Annual Report on Form 10-K for the year ended December 31, 2013.

The Board of Directors adopts the charter for the Audit Committee. John D. Harkey, Jr., Matthew S. Ramsey and K. Rick Turner serve as elected members of the Audit Committee. Mr. Harkey currently serves as the Chair of the Audit Committee. Mr. Harkey currently serves as a member or chairman of the audit committee of four other publicly traded companies, including the general partner of Regency, in addition to his service as a member of the Audit Committee of our General Partner. As required by Rule 303A.07 of the NYSE Listed Company Manual, the Board of Directors of our General Partner has determined that such simultaneous service does not impair Mr. Harkey's ability to effectively serve on our Audit Committee.

Compensation and Nominating/Corporate Governance Committees

Although we are not required under NYSE rules to appoint a Compensation Committee or a Nominating/Corporate Governance Committee because we are a limited partnership, the Board of Directors of LE GP, LLC has previously 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, 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 our General Partner, the Parent Company, ETP or its subsidiaries, or Regency or its subsidiaries. Subsequent to the resignations of Paul E. Glaske and Bill W. Byrne from the board of directors of our General Partner effective June 30, 2011, ETE did not have a compensation committee; therefore, the members of the board of directors of our General Partner who would be eligible to be members of the Compensation Committee served in that capacity. In February 2013, Messrs. Harkey and Ramsey were appointed to the ETE Compensation Committee.

Matters relating to the nomination of directors or corporate governance matters were addressed to and determined by the full Board of Directors for the period ETE did not have a compensation committee.

In the discussion and analysis that follows, we have used the term, “ETE Compensation Committee,” to refer to either or both of (i) our compensation committee, which existed through June 2011 and from February 2013 to the present, and (ii) the eligible members of the board of directors of our General Partner, functioning in the capacity of our compensation committee subsequent from June 2011 to February 2013.

The responsibilities of the ETE Compensation Committee include, among other duties, the following:

- annually review and approve goals and objectives relevant to compensation of our President and CFO, if applicable;
- annually evaluate the President and CFO’s performance in light of these goals and objectives, and make recommendations to the Board of Directors with respect to the President and CFO’s compensation levels, if applicable, based on this evaluation;
- make determinations with respect to the grant of equity-based awards to executive officers under ETE’s equity incentive plans;
- periodically evaluate the terms and administration of ETE’s long-term incentive plans to assure that they are structured and administered in a manner consistent with ETE’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, President and CFO or executive officer compensation; and
- perform other duties as deemed appropriate by the Board of Directors.

The responsibilities of the ETP Compensation Committee include, among other duties, the following:

- annually review and approve goals and objectives relevant to compensation of the Chief Executive Officer, or the CEO, if applicable; annually evaluate the CEO’s performance in light of these goals and objectives, and make recommendations to the Board of Directors of ETP with respect to the CEO’s compensation levels based on this evaluation, if applicable;
- based on input from, and discussion with, the CEO, make recommendations to the Board of Directors of ETP 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 ETP’s 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 ETP.

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. Our non-management directors 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 of the independent directors, or any one director serving on the Board of Directors by sending written correspondence addressed to the desired person, committee or group to the attention of Sonia Aubé at Energy Transfer Equity, L.P., 3738 Oak Lawn Avenue, Dallas, Texas, 75219. 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 Our 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 27, 2014. Executive officers and directors are elected for indefinite terms.

Name	Age	Position with Our General Partner
John W. McReynolds	63	Director and President
Kelcy L. Warren	58	Director and Chairman of the Board
Jamie Welch	47	Director and Group Chief Financial Officer and Head of Business Development
John D. Harkey, Jr.	53	Director
Marshall S. (Mackie) McCrea, III	54	Director
Matthew S. Ramsey	59	Director
K. Rick Turner	56	Director

Messrs. Warren and McCrea also serve as directors of ETP's General Partner. Messrs. McReynolds and Harkey also serve as directors of Regency's General Partner.

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

John W. McReynolds. Mr. McReynolds has served as our President since March 2005 and as a Director since August 2005. He served as our Chief Financial Officer from August 2005 to June 2013 and has previously served as a director of Energy Transfer Partners from August 2001 through May 2010. Mr. McReynolds has also served as a director of Regency since May 2010. Prior to becoming President of Energy Transfer Equity, Mr. McReynolds was a partner with the international law firm of Hunton & Williams LLP for over 20 years. As a lawyer, Mr. McReynolds specialized in energy-related finance, securities, partnerships, mergers and acquisitions, syndication and litigation matters, and served as an expert in special projects for Boards of Directors for public companies. The members of our General Partner selected Mr. McReynolds to serve as a director because of his legal background and his extensive experience in energy-related corporate finance. Mr. McReynolds has relationships with executives and senior management at several companies in the energy sector, as well as with investment bankers who cover the industry.

Kelcy L. Warren. Mr. Warren was appointed Co-Chairman of the Board of Directors of our General Partner, LE GP, LLC, effective upon the closing of our IPO. On August 15, 2007, Mr. Warren became the sole Chairman of the Board of our General Partner and the Chief Executive Officer and Chairman of the Board of the General Partner of ETP. Prior to that, Mr. Warren had served as Co-Chief Executive Officer and Co-Chairman of the Board of the General Partner of ETP since the combination of the midstream and intrastate transportation storage operations of ETC OLP and the retail propane operations of Heritage in January 2004. Mr. Warren also serves as Chief Executive Officer of the General Partner of ETC OLP. Prior to the combination of the operations of ETP and Heritage Propane, Mr. Warren served as President of the General Partner of ET Company I, Ltd. the entity that operated ETP's midstream assets before it acquired Aquila, Inc.'s midstream assets, 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 members of our General Partner selected Mr. Warren to serve as a director and as Chairman because he is ETP'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.

Jamie Welch. Mr. Welch has served as the Group Chief Financial Officer and Head of Business Developments for the Energy Transfer family since June 2013. Mr. Welch has also served on the Board of Directors of ETE, ETP, and Sunoco Logistics since June 2013. Before joining ETE, Mr. Welch was Head of the EMEA Investment Banking Department and Head of the Global Energy Group at Credit Suisse. He was also a member of the IBD Global Management Committee and the EMEA Operating Committee. Mr. Welch joined Credit Suisse First Boston in 1997 from Lehman Brothers Inc. in New York, where he was a Senior Vice President in the global utilities & project finance group. Prior to that he was an attorney with Milbank, Tweed, Hadley & McCloy (New York) and a barrister and solicitor with Minter Ellison in Melbourne Australia. The members of our General Partner selected Mr. Welch to serve on the Board of Directors because of his understanding of energy-related corporate finance gained through his experience in the investment banking and legal fields.

John D. Harkey, Jr. In May 2006, Mr. Harkey was elected as a director of our General Partner and member of the Audit Committee. He currently serves as the Chairman of the Audit Committee of our General Partner. The members of our General Partner selected Mr. Harkey to serve as a director because of his background in corporate finance, as well as his experience as a director on the boards and audit committees of several other public companies. Mr. Harkey was elected Chairman of the Board of Directors of

Regency GP LLC in May 2010. Mr. Harkey has served as Chief Executive Officer and Chairman of Consolidated Restaurant Companies, Inc., since 1998. Mr. Harkey currently serves on the Board of Directors of Leap Wireless International, Inc., Loral Space & Communications, Inc., Emisphere Technologies, Inc., and the Board of Directors for the Baylor Health Care System Foundation. He currently serves on the Audit Committee of Loral and Regency. He also serves on the President's Development Council of Howard Payne University and on the Executive Board of Circle Ten Council of the Boy Scouts of America.

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 ETP GP and has served in that capacity since June 2008. Prior to that, he served as President – Midstream 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 the 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 members of our General Partner selected Mr. McCrea to serve as a director because he brings extensive project development and operations 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.

Matthew S. Ramsey. Mr. Ramsey was appointed as a director on July 17, 2012 and currently serves as a member of the Audit and Compensation Committees. Mr. Ramsey is presently President of RPM Exploration, Ltd., a private oil and gas exploration partnership generating and drilling 3-D seismic prospects on the Gulf Coast of Texas. Mr. Ramsey is also President of Ramsey Energy Management, LLC, the General Partner of Ramsey Energy Partners, I, Ltd., a private oil and gas partnership, and as President of Dollarhide Management, LLC, the General Partner of Deerwood Investments, Ltd., a private oil and gas partnership. Additionally, Mr. Ramsey is President of Gateshead Oil, LLC, a private oil and gas partnership. He also serves as Manager of MSR Energy, LLC, the general partner of Shafter Lake Energy Partners, Ltd., a private oil and gas exploration limited partnership. In 2014, Mr. Ramsey joined the board of directors of RSP Permian, Inc. (NYSE: RSPP), where he serves as chairman of the compensation committee and as a member of the audit committee. Mr. Ramsey formerly served as President of DDD Energy, Inc. until its sale in 2002. From 1996 to 2000, Mr. Ramsey served as President and Chief Executive Officer of OEC Compression Corporation, Inc., a publicly traded oil field service company, providing gas compression services to a variety of energy clients. Previously, Mr. Ramsey served as Vice President of Nuevo Energy Company, an independent energy company. Additionally, he was employed by Torch Energy Advisors, Inc., a company providing management and operations services to energy companies including Nuevo Energy, last serving as Executive Vice President. Mr. Ramsey joined Torch Energy as Vice President of Land and was named Senior Vice President of Land in 1992. Prior to joining Torch Energy Advisors, Inc., Mr. Ramsey was self employed for eleven years. Mr. Ramsey holds a B.B.A. in Marketing from the University of Texas at Austin and a J.D. from South Texas College of Law. Mr. Ramsey is a graduate of Harvard Business School Advanced Management Program. Mr. Ramsey is licensed to practice law in the State of Texas. He is qualified to practice in the Western District of Texas and the United States Court of Appeals for the Fifth Circuit. Mr. Ramsey formerly served as a Director of Southern Union Company. The members of our General Partner recognize Mr. Ramsey's vast experience in the oil and gas space and believe that he provides valuable industry insight as a member of our Board of Directors.

K. Rick Turner. Mr. Turner is a private equity executive with several groups after having recently retired from the Stephens' family entities, which he had worked for since 1983. He first became a private equity principal in 1990 after serving as the Assistant to the Chairman, Jackson T. Stephens. His areas of focus have been oil and gas exploration, natural gas gathering, processing industries, and power technology. Prior to joining Stephens, he was employed by Peat, Marwick, Mitchell and Company. Mr. Turner currently serves as a director of North American Energy Partners Inc., AmeriGas and TMI, LLC. Mr. Turner has served as a director of our General Partner since October 2002. Mr. Turner earned his B.S.B.A. from the University of Arkansas and is a non-practicing Certified Public Accountant. The members of our General Partner selected Mr. Turner based on his industry knowledge, his background in corporate finance and accounting, and his experience as a director and audit committee member on the boards of several other companies.

Compensation of the General Partner

Our General Partner does not receive any management fee or other compensation in connection with its management of the Parent Company.

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 certain reporting persons that no Forms 5 were required for those persons, we believe that for our year ended December 31, 2013, all filing requirements applicable to its officers, directors, and greater than 10% beneficial owners were met in a timely manner, with the exception of two late filings of Form 4 for two transactions by Mr. Ramsey.

ITEM 11. EXECUTIVE COMPENSATION

Overview

As a limited partnership, we are managed by our General Partner. Our General Partner is majority owned by Mr. Kelcy Warren. Our limited partner interests are owned approximately 25% by affiliates and approximately 75% by the public.

We own 100% of ETP GP and its general partner, ETP LLC. We refer to ETP GP and ETP LLC together as the "ETP GP Entities." ETP GP is the general partner of ETP. All of ETP's employees receive employee benefits from the operating companies of ETP.

We own 100% of Regency GP and its general partner, Regency LLC. We refer to Regency GP LP and Regency GP LLC together as the "Regency GP Entities." Regency GP is the general partner of Regency. All of Regency's employees receive employee benefits from the operating companies of Regency.

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. In addition, to provide comprehensive disclosure of our executive compensation, we are also providing information as to the executive compensation of the ETP GP Entities, since the shared service agreement with ETP may place ETP's executives in a position to perform policy making functions for ETE from time to time, even though none of these persons is an executive officer of the Parent Company. Accordingly, the persons we refer to in this discussion as our "named executive officers" are the following:

ETE Executive Officers

- John W. McReynolds, President; and
- Jamie Welch, Group Chief Financial Officer and Head of Business Development.

ETP GP Entities Executive Officers

- 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 of Midstream Operations.

Our Philosophy for Compensation of Executives

Our General Partner. 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 or "at-risk" compensation and that executives' total compensation levels should be very competitive in the marketplace for executive talent and abilities. Our General Partner seeks a total compensation program that provides for a slightly below the median market annual base compensation rate but incentive-based compensation composed of a combination of compensation vehicles to reward both short and long-term performance that are both targeted to pay-out at approximately the top-quartile of market. Our General Partner believes the incentive-based balance is achieved by the payment of annual discretionary cash bonuses and grants of restricted unit awards. Our General Partner believes the performance of our operating subsidiaries and the contribution of our management toward the achievement of the financial targets and other goals of those subsidiaries should be considered in determining annual discretionary cash bonuses.

ETP GP Entities. The ETP GP Entities also believe that a significant portion of each executives' compensation should be incentive-based or "at-risk" compensation and that executives' total compensation levels should be very competitive in the marketplace for executive talents and abilities. ETP GP seeks a total compensation program that provides for a slightly below the median market annual base compensation rate but incentive-based compensation composed of a combination of compensation vehicles to reward both short and long-term performance that are both targeted to pay-out at approximately the top-quartile of market. ETP GP believes the incentive-based balance is achieved by (i) the payment of annual discretionary cash bonuses that consider the achievement of ETP's financial performance objectives for a fiscal year set at the beginning of such fiscal year and the individual contributions of its named executive officers to the success of ETP and the achievement of the annual financial performance objectives and (ii) the annual grant of restricted unit awards under ETP's equity incentive plan(s), which awards are intended to provide a longer term incentive and retention value to its key employees to focus their efforts on increasing the market price of its publicly traded units and to increase the cash distribution ETP pays to its Unitholders. Prior to December 2012, ETP's equity awards were been primarily in the form of restricted unit awards that vest over a specified time period, with substantially all of these types of unit 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. The ETP GP Entities believe that these equity-based incentive arrangements are important in attracting and retaining executive officers and key employees as well as motivating these individuals to achieve ETP's business objectives. The equity-based compensation reflects the importance ETP GP places on aligning the interests of its named executive officers with those of ETP's Unitholders.

While ETE is responsible for the direct payment of the compensation of our named executive officers as an employee of ETE, ETE does not participate or have any input in any decisions as to the compensation levels or policies of our General Partner, the ETP GP Entities or the Regency GP Entities. As discussed below, our compensation committee or the eligible members of board of directors of our General Partner at times when we have not had a compensation committee, is responsible for the compensation policies and compensation level of the executive officers of our General Partner. In this discussion, we refer to either or both of our compensation committee or such members of our board of directors as the "ETE Compensation Committee."

ETP also does not participate or have any input in any decisions as to the compensation policies of the ETP GP Entities or the compensation levels of the executive officers of the ETP GP Entities. The compensation committee of the board of directors of the ETP GP Entities (the "ETP Compensation Committee") is responsible for the approval of the compensation policies and the compensation levels of the executive officers of the ETP GP Entities.

ETE and ETP directly pay their respective executive officers in lieu of receiving an allocation of overhead related to executive compensation from their respective general partner. For the year ended December 31, 2013, ETE and ETP paid 100% of the compensation of the executive officers of their respective general partner as each entity represents the only business currently managed by such general partner.

For a more detailed description of the compensation to ETE's and ETP GP's named executive officers, please see "– Compensation Tables" below.

Distributions to Our General Partner

Our General Partner 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 its general partner interest as 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. Distributions to our General Partner are described in detail in Note 8 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.

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

Compensation Philosophy

Each of ETE's and ETP's compensation programs are structured to provide the following benefits:

- reward executives with an industry-competitive total compensation package of competitive base salaries and significant incentive opportunities yielding a total compensation package approaching the top-quartile of the market;

- 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 or "at-risk" compensation; and
- reward individual performance.

Components of Executive Compensation

For the year ended December 31, 2013, the compensation paid to ETE's and ETP GP's named executive officers consisted of the following components:

- annual base salary;
- non-equity incentive plan compensation consisting solely of discretionary cash bonuses;
- time-vested restricted unit awards under the equity incentive plan(s);
- payment of distribution equivalent rights ("DERs") on unvested time-based restricted unit award under our equity incentive plan;
- vesting of previously issued time-based awards issued pursuant to our equity incentive plans;
- equity incentive plan compensation.

Mr. Warren, the Chairman of the Board of ETE and the CEO of ETP GP, 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

Presently, the compensation committees of ETE and its subsidiaries consider relevant data available to them to assess the competitive position with respect to base salary, annual short-term incentives and long-term incentive compensation for our executive officers. The boards of directors and compensation committees of ETE and its subsidiaries also consider individual performance, levels of responsibility, skills and experience.

Periodically, the compensation committees of ETE and/or its affiliates engage a third-party consultant to provide market information for compensation levels at peer companies in order to assist the compensation committees in the determination of compensation levels for executive officers. Most recently, the compensation committee of ETP engaged Mercer (US) Inc. ("Mercer") during the year ended December 31, 2013 to both (i) evaluate the market competitiveness of total compensation levels for certain members of senior management, including its named executive officers; (ii) assist in the determination of appropriate compensation levels for its senior management, including the named executive officers; and (iii) to confirm that our compensation programs were yielding compensation packages consistent with our overall compensation philosophy. This review by Mercer was deemed necessary given the series of transforming transactions ETE and its affiliates have completed over the past few years, which have significantly increased the size and scale of ETE and its subsidiaries from both a financial and asset perspective.

In conducting its review, Mercer worked with ETP to identify a "peer group" of 15 leading companies in the energy industry that most closely reflect ETE's and ETP's profile in terms of revenues, assets and market value as well as compete with ETE and ETP for talent at the senior management level. The identified companies were:

• Conoco Phillips	• Anadarko Petroleum
• Enterprise Products Partners, L.P.	• ONEOK Partners, L.P.
• Plains All American Pipeline, L.P.	• EOG Resources, Inc.
• Halliburton Company	• Kinder Morgan Energy Partners, L.P.
• National Oilwell Varco, Inc.	• The Williams Companies, Inc.
• Baker Hughes Incorporated	• Enbridge Energy Partners, L.P.
• Apache Corp.	• DCP Midstream Partners, L.P.
• Marathon Oil Corporation	

The compensation analysis provided by Mercer covered all major components of total compensation, including annual base salary, annual short-term cash bonus and long-term incentive awards for the senior executives of these companies. The Compensation Committees of ETE and ETP utilized the information provided by Mercer to compare the levels of annual base salary, annual short-term cash bonus and long-term equity incentive awards at these other companies with those of its named executive officers to ensure that compensation of our named executive officers is both consistent with our compensation philosophy and competitive with the compensation for executive officers of these other companies. The Compensation Committee also considered and reviewed the results of the study performed by Mercer to ensure the results indicated that our compensation programs were yielding a competitive total compensation model prioritizing incentive-based compensation and rewarding achievement of short and long-term performance objectives. The Compensation Committee also specifically evaluated benchmarked results for the annual base salary, annual short-term cash bonus or long-term equity incentive awards of the named executive officers to compensation levels at the identified "peer group" companies. Mercer did not provide any non-executive compensation services for ETE or ETP during 2013.

ETE Base Salary. As discussed above, the base salaries of our named executive officers are targeted to yield an annual base salary slightly below the median level of market and are determined by the ETE Compensation Committee after taking into account the recommendation of Mr. Warren. The ETE Compensation Committee did not increase Mr. McReynolds' base salary for 2013. The ETE Compensation Committee did not increase the base salary of Mr. Welch given his employment with the Partnership began in 2013.

ETP Base Salary. The base salaries of ETP's named executive officers are determined by the ETP Compensation Committee, which take into account the recommendations of Mr. Warren. For 2013, the ETP Compensation Committee approved an increase of 6.7% to Mr. McCrea's annual base salary, 5.9% to Mr. Salinas' annual base salary, and 10% to Mr. Mason's annual base salary. The ETP Compensation Committee determined that such increases were warranted based on the results of the Mercer study and the factors described below under "Annual Bonus." The ETP 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 and the associated increased in role and responsibility of each named executive office in light of the same.

ETE Annual Bonus. For 2013, the ETE Compensation Committee approved short-term annual cash bonus targets for Messrs. McReynolds and Welch of 125% of their annual base salary, which reflected increases from an annual cash bonus target of 100% of annual base salary. The new targets were adopted consistent with the results of the Mercer study. In February 2014, the ETE Compensation Committee approved a cash bonus relating to the 2013 calendar year to Messrs. McReynolds and Welch in the amounts of $700,721 and $550,000, respectively. In approving this cash bonus, the ETE Compensation Committee took into account the significant role that Mr. McReynolds has as the senior management person for ETE with respect to managing the business of ETE, as well as his role in providing strategic advice related to multiple other transactions among ETE and its subsidiaries. The ETE Compensation Committee also took into account the individual performance of Mr. McReynolds with respect to promoting ETE's financial, strategic and operating objectives for 2013. In the case of Mr. Welch for 2013, his bonus amount was based on the terms of his of his original offer letter of April 29, 2013, which provided for a bonus guarantee of $550,000 for 2013. Moving forward, Mr. Welch's future bonus awards will be based on factors consistent with those utilized for Mr. McReynolds as well as those utilized by the ETP Compensation Committee in considering awards to the ETP GP named executive officers.

ETP Annual Bonus. In addition to base salary, the ETP Compensation Committee makes a determination whether to award named executive officers of the ETP GP Entities, other than ETP's CEO (who has voluntarily elected to forego any annual bonuses), discretionary annual cash bonuses following the end of the year. These discretionary bonuses, if awarded, are intended to reward the named executive officers of the ETP GP Entities 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 ETP's profitability and success during such year. In this regard, the ETP Compensation Committee takes into account whether ETP 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 ETP Compensation Committee also considers the recommendation of ETP's CEO in determining the specific cash bonus amounts for each of the other named executive officers of the ETP GP Entities. The ETP Compensation Committee does not establish its own financial performance objectives in advance for purposes of determining whether to approve any annual bonuses, and the ETP Compensation Committee does not utilize any formulaic approach to determining annual bonuses.

ETP'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 ETP's business. The evaluation of ETP's performance versus its internal financial budget is based on the ETP's internal EBITDA budget for a calendar year. In general, ETP's Compensation Committee believes that performance at or above ETP's internal EBITDA budget would support bonuses to named executive officers of the ETP GP Entities ranging from 100% to 140% of their annual bonus target. For 2013, ETP's Compensation Committee approved a short-term annual cash bonus target for Mr. McCrea of 140% of his annual base salary, 120% of his annual base salary for Mr. Salinas, 125% of his annual base salary for Mr. Mason and 100% of his annual base salary for Mr. Cargile. In the cases of Messrs. McCrea, Salinas and Mason, their annual bonus target was increased to its new level from a target of 100% of annual base salary consistent with the results of the Mercer study, while Mr. Cargile's target remained at its 2012 level of 100% of annual base salary. In February 2014, ETP's Compensation Committee approved cash bonuses relating to the 2013 calendar year to Messrs. McCrea, Salinas, Mason and Cargile of $1,080,961, $524,423, $646,635 and $305,000, respectively. The individual bonus amounts for each named executive officer, other than ETP's CEO, also reflect the ETP Compensation Committee's view of the impact of such individual's efforts and contributions towards (i) achievement of ETP'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 ETP and increase distributable cash flow, (iv) the overall management of ETP's business, and (v) the individual performances of these individuals with respect to promoting ETP's financial, strategic and operating objectives for 2013. The cash bonuses awarded to each of the executive officers for 2013 were consistent with the target.

ETE Equity Awards. The Energy Transfer Equity Long-Term Incentive Plan authorizes the ETE Compensation Committee, in its discretion, to grant awards of restricted units, unit options and other awards related to ETE units at such times and upon such terms and conditions as it may determine in accordance with each such plan. The ETE Compensation Committee determined and/or approved the terms of the unit grants awarded to the named executive officers of ETE, including the number of ETE 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 this equity incentive plan have consisted of restricted unit awards that are subject to vesting over a specified time period. ETE Common Units are issued upon grant of the award, subject to forfeiture of unvested units upon termination of employment during the vesting period.

In connection with Jamie Welch joining ETE as Group Chief Financial Officer and Head of Business Development effective as of April 29, 2013, ETE agreed to award Mr. Welch 1,500,000 Common Units of ETE (after adjustment for the January 2014 two-for-one split), subject to a period of restriction, under the Energy Transfer Equity, L.P. Long-Term Incentive Plan pursuant to a Unit Award Under Long-Term Incentive Plan and the Time-Vested Restricted Unit Award Agreement, each dated as of April 29, 2013 (the "Original Award Agreements"). On December 23, 2013, ETE and Mr. Welch entered into (i) a Rescission Agreement in order to rescind the original offer letter to the extent it relates to the award of 1,500,000 Common Units of ETE (after adjustment for the January 2014 two-for-one split) to Welch, the Original Award Agreements, and the receipt of cash amounts by Mr. Welch with respect to such awarded units and (ii) a new Class D Unit Agreement between ETE and Mr. Welch (the "Class D Unit Agreement") providing for the issuance to Mr. Welch of an aggregate of 1,540,000 Class D Units of ETE (after unit split adjustment), which number of Class D Units includes an additional 40,000 Class D Units that were issued to Mr. Welch in connection with other changes to his original offer letter.

Under the terms of the Class D Unit Agreement, 30% of the Class D Units granted to Mr. Welch will convert to ETE Common Units on a one-for-one basis on March 31, 2015, and the remaining 70% will convert to ETE Common Units on a one-for-one basis on March 31, 2018, subject in each case to Mr. Welch being in Good Standing with ETE (as defined in the Class D Unit Agreement) and there being a sufficient amount of gain available to be allocated to the Class D Units being converted so as to cause the capital account of each such unit to equal the capital account of an ETE Common Unit on the conversion date. Upon a Change of Control (as defined in the Class D Unit Agreement), all of the Class D Units issued to Mr. Welch will convert to ETE Common Units subject again to the availability of a sufficient amount of allocable gain and the requirement of Good Standing will cease to apply.

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

In addition to his initial award discussed above, Mr. Welch is eligible on an annual basis to receive annual long-term incentive awards under the Energy Transfer Equity, L.P. Long-Term Incentive Plan or the long-term incentive plans of ETE's affiliates. For 2013, ETE's Compensation Committee set Mr. Welch's long-term incentive award target at 200% of his base. As described below in the section titled *Subsidiary Equity Awards*, for 2013, in discussions between the ETE Compensation Committee and the Chairman of the Board of ETE, as well as the compensation committees of the general partners of ETP, Regency and Sunoco Logistics, it was determined that for 2013 that value of Mr. Welch's ward would be comprised of restricted/phantom unit awards under the ETP and Regency equity incentive plans in consideration of his roles and responsibilities as Group Chief Financial Officer for all of the partnerships under ETE's umbrella and as a member of the Boards of Directors of the general partners of ETP and Sunoco Logistics. It is anticipated that the long-term equity awards of Mr. Welch will continue to recognize some levels of aggregation of restricted/phantom units being awarded under the ETP, Regency and Sunoco Logistics equity incentive plans in future years. Each of the unit awards provide for vesting over a five-year period, with 60% 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 and entitle Mr. Welch to receive DERs on the unvested units.

ETP Equity Awards. Each of ETP's 2004 Unit Plan and 2008 Incentive Plan authorizes the ETP Compensation Committee, in its discretion, to grant awards of restricted units, unit options and other awards related to ETP common units at such times and upon such terms and conditions as it may determine in accordance with each such plan. The ETP Compensation Committee determined and/or approved the terms of the unit grants awarded to the named executive officers of the ETP GP Entities, including the number of ETP common units subject to the unit award and the vesting structure of those unit awards. All of the awards granted to ETP's named executive officers under these equity incentive plans have consisted of restricted unit awards that are subject to vesting over a specified time period. Upon vesting of any unit award, ETP common units are issued.

In consideration of the results of the Mercer study for 2013, the ETP Compensation Committee approved increased long-term incentive awards targets for certain of the ETP named executive officers. Mr. McCrea's long-term incentive target increased from 330% of his annual base salary to 700% of his base salary, Mr. Salinas' annual long-term incentive target increased from 250% of his annual base salary to 300%, Mr. Mason's annual long-term incentive target increased from 270% of his annual base salary to 400% and Mr. Cargile's target remained at 150% of annual base salary. In December 2013, the ETP Compensation Committee approved grants of unit awards to Messrs. McCrea, Salinas, Mason and Cargile of 69,375 ETP common units, 16,724 ETP common units, 40,923 ETP common units and 9,500 ETP common 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. As described below in the section titled *Subsidiary Equity Awards*, for 2013, in discussions between the ETP Compensation Committee and the CEO as well as the compensation committee of the general partner of Sunoco Logistics, it was determined that approximately 33% of the total long-term incentive award target values of Messrs. McCrea and Salinas would be composed of restricted units awarded under Sunoco Logistics' equity incentive plan in considerations for their roles and responsibilities at Sunoco Logistics in addition to ETP. At Sunoco Logistics, Mr. McCrea serves as Chairman of the Board of Sunoco Logistics' general partner and Mr. Salinas serves as a member of the board and Chief Financial Officer of Sunoco Logistics' general partner. It is expected that the long-term equity awards of Messrs. McCrea and Salinas will recognize a similar aggregation of restricted units being awarded under our equity incentive plan and Sunoco Logistics' equity incentive plan in future years. The terms and conditions of the restricted unit awards to Messrs. McCrea and Salinas under the Sunoco Logistics equity plan are identical to the terms and conditions of the restricted unit awards under ETP's equity plan to Messrs. McCrea and Salinas.

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, DER cash payment promptly following each such distribution by ETP to its Unitholders. In approving the grant of such unit awards, the ETP 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 Partner'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 ETP common units pursuant to ETP's 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 ETP common units.

The unit awards under ETP's equity incentive plans generally require the continued employment of the recipient during the vesting period, provided however, the unvested awards will be accelerated in the event of a change in control of ETP or the death or disability of the award recipient prior to the applicable vesting period being satisfied. The ETP 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 ETP Compensation Committee did not accelerate the vesting of unit awards to any named executive officers in 2013.

ETE Unit Ownership Guidelines. In December 2013, the Board of Directors of our General Partner adopted the ETE Executive Unit Ownership Guidelines ("the Guidelines"), which set forth minimum ownership guidelines applicable to certain executives of ETE with respect to ETE Common Units representing limited partnership interests in ETE. The applicable unit ownership guidelines are denominated as a multiple of base salary, and the amount of ETE Common Units required to be owned increases with the level of responsibility. Under these guidelines, Mr. McReynolds as ETE's President is expected to own ETE Common Units having a minimum value of five times his base salary, while Mr. Welch is expected to own ETE Common Units having a minimum value of four times his base salary. In addition to the named executive officers, these Guidelines also apply to other covered executives, which are expected to own either directly or indirectly in accordance with the terms of the Guidelines ETE Common Units having minimum values ranging from two to four times their respective base salaries.

The ETE Compensation Committee believes that the ownership of ETE Common Units, as reflected in these Guidelines, is an important means of tying the financial risks and rewards for its executives to ETE's total unitholder return, aligning the interests of such executives with those of ETE's Unitholders, and promoting ETE's interest in good corporate governance.

Covered executives are generally required to achieve their ownership level within five years of becoming subject to the guidelines; however, certain covered executives, based on their tenure as an executive, are required to achieve compliance within two years of the December 2013 effective date of the Guidelines. Thus, compliance with the guidelines will be required for Mr. McReynolds beginning in December 2015 and for Mr. Welch in December 2018.

Covered executives may satisfy the guidelines through direct ownership of ETE Common Units or indirect ownership by certain immediate family members. Direct or indirect ownership of ETE Common Units shall count on a one to one ratio for purposes of satisfying minimum ownership requirements; however, unvested unit awards may not be used to satisfy the minimum ownership requirements.

Executive officers who have not yet met their respective guideline must retain and hold all ETE Common Units (less ETE Common Units sold to cover the executive's applicable taxes and withholding obligation) received in connection with long-term incentive awards. Once the required ownership level is achieved, ownership of the required ETE Common Units must be maintained for as long as the covered executive is subject to the guidelines. However, those individuals who have met or exceeded their applicable ownership guideline may dispose of the ETE Common Units in a manner consistent with applicable laws, rules and regulations, including regulations of the SEC and ETE's internal policies, but only to the extent that such individual's remaining ownership of ETE Common Units would continue to exceed the applicable ownership guideline.

The Board of Directors of ETP's General Partner approved and adopted the ETP Executive Ownership Guidelines (the "ETP Guidelines") in December 2013 as well. The ETP Guidelines are substantially identical to the Guidelines described above. Under the ETP Guidelines, Mr. McCrea, the President and Chief Operating Officer of ETP is expected to own ETP common units having a minimum value of five times his base salary, while each of ETP's remaining named executive officers (other than the CEO) are expected to own ETP common units having a minimum value of four times their respective base salary. In addition to the named executive officers, the ETP Guidelines also apply to other covered ETP executives, which executives are expected to own either directly or indirectly in accordance with the terms of the ETP Guidelines ETP common units having minimum values ranging from two to four times their respective base salary.

Subsidiary Equity Awards.

ETE Named Executive Officers. In his role as Group Chief Financial Officer, Mr. Welch provides services to each of ETE, ETP, Regency and Sunoco Logistics. Mr. Welch also serves on the board of the general partners of ETE, ETP and Sunoco Logistics. In connection with these roles for each ETP and Regency, the compensation committees of the general partners of ETP and Regency, in consultation with ETE's President, determined that for 2013, Mr. Welch's long-term incentive award would be split equally between restricted/phantom unit awards under the ETP and Regency equity incentive plans. As such, (i) the ETP Compensation Committee awarded Mr. Welch a time-based restricted unit award of 6,900 units; and (ii) the Regency Compensation Committee awarded Mr. Welch a time-based phantom unit award of 15,000 units. Each of the 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 and entitle Mr. Welch to receive DERs on the unvested units.

ETP Named Executive Officers. In addition to their roles as officers of ETP GP, Messrs. McCrea and Salinas also serve as officers and directors of the general partner of Sunoco Logistics. In connection with those roles at Sunoco Logistics' general partner, in December 2013, the compensation committee of Sunoco Logistics' general partner awarded Messrs. McCrea and Salinas time-based restricted units of Sunoco Logistics in the amount of 27,300 units and 6,550 units, respectively. The terms and conditions of the restricted unit awards to Messrs. McCrea and Salinas under the Sunoco Logistics equity plan are identical to the terms and conditions of the restricted unit awards under ETP's equity plan to Messrs. McCrea and Salinas.

The previous annual grant of Sunoco Logistics equity awards occurred in January 2013, at which time Messrs. McCrea and Salinas were granted 16,667 units and 8,333 units, respectively. These awards are reflected as compensation in 2013 for Messrs. McCrea and Salinas in the "Compensation Tables" section below.

Affiliate Equity Awards. McReynolds Energy Partners, L.P., the general partner of which is owned and controlled by the President of our General Partner, has voluntarily elected to award to certain officers of ETP certain rights related to units of ETE previously issued by ETE to such partnership. These rights include the economic benefits of ownership of these ETE units based on a five-year vesting schedule whereby the officer vested in the ETE units at a rate of 20% per year. As these ETE units 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 were paid by ETE or ETP. ETP recognized 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. As of December 31, 2013, no such affiliate equity awards remained outstanding. During 2013, Messrs. McCrea and Salinas vested in rights related to ETE units of 84,000 and 96,000, respectively (after adjustment for ETE's two-for-one Common Unit split in January 2014).

Qualified Retirement Plan Benefits. ETP GP has established a defined contribution 401(k) plan, which covers substantially all employees of ETE and ETP, including named executive officers. Employees may elect to their up to 100% of defined 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 amounts deferred by the participant and the amounts deferred by the Partnership or ETP are fully vested at all times. We provide this benefit as a means to incentivize employees and provide them with an opportunity to save for their retirement.

Beginning in January 2013, the Partnership provides a 3% profit sharing contribution to employee 401(k) accounts for all employees with a base compensation below a specified threshold. The contribution is in addition to the 401(k) matching contribution and employees become vested based on years of service.

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

Termination Benefits. ETE's and ETP's 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. Each of ETE's and ETP's long-term incentive plans provides for immediate vesting of all unvested unit awards in the event of a change of control, as defined in the respective plan. Please refer to "– Compensation Tables – Potential Payments Upon a Termination or Change of Control" for additional information.

In addition, ETP GP has also adopted the ETP GP Severance Plan and Summary Plan Description effective as of June 12, 2013, (the "Severance Plan"), which provides for payment of certain severance benefits in the event of Qualifying Termination (as that term is defined in the Severance Plan). In general, the Severance Plan provides payment of two weeks of annual base salary for each year or partial year of employment service with the ETP up to a maximum of fifty-two weeks or one year of annual base salary (with a minimum of four weeks of annual base salary) and up to three months of continued group health insurance coverage. The Severance Plan also provides that the ETP may determine to pay benefits in addition to those provided under the Severance Plan based on special circumstances, which additional benefits shall be unique and non-precedent setting. The Severance Plan is available to all salaried employees on a nondiscriminatory basis; therefore, amounts that would be payable to ETE's and/or ETP's named executive officers upon a Qualified Termination have been excluded from "Compensation Tables – Potential Payments Upon a Termination or Change of Control" below.

Deferred Compensation Plan. ETE does not have a deferred compensation plan. ETP maintains a deferred compensation plan ("DC Plan"), which permits eligible highly compensated ETP 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 ETP 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, ETP has not made any discretionary contributions to participants' accounts and currently has 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 three or five years upon retirement, and in a lump sum upon other termination. Participants may also elect to take lump-sum in-service withdrawals five years or longer in the future, and such scheduled in-service withdrawals may be further deferred prior to the withdrawal date. 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 distributions pursuant to his deferral agreement.

Risk Assessment Related to our Compensation Structure. We believe that the compensation plans and programs for named executive officers of ETE and ETP, as well as our other employees, are appropriately structured and are not reasonably likely to result in material risk to ETE or ETP. We believe these compensation plans and programs are structured in a manner that does not promote excessive risk-taking that could harm the value of ETE or ETP or reward poor judgment. We also believe ETE and ETP have allocated compensation among base salary and short and long-term compensation in such a way as to not encourage excessive risk-taking. In particular, ETE and ETP generally do not adjust base annual salaries for 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 a portion of our operations. ETE and ETP generally determine whether, and to what extent, their respective named executive officers receive a cash bonus based on achievement of specified financial performance objectives as well as the individual contributions of our named executive officers to the Partnership's success. ETE and ETP 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 ETE's and ETP's long-term incentive awards ensures that the interests of employees align with those of the respective unitholders of ETE and ETP for the long-term performance of ETE and ETP.

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 unit-based compensation arrangements, including equity-based awards issued to certain of ETP's named executive officers by Mr. McReynolds (as discussed above), we record compensation expense over the vesting period of the awards, as discussed further in Note 9 to our consolidated financial statements.

Compensation Committee Interlocks and Insider Participation

During 2012, matters concerning Mr. McReynolds' compensation were deliberated by the members of the board of directors of our General Partner who would be eligible to serve on the ETE Compensation Committee, which consisted of Messrs. Harkey, Ramsey and Turner, as well as former board members, Mr. Ray C. Davis and Mr. David R. Albin. Messrs. Ramsey and Albin participated in such deliberations during the portion of 2012 for which they served on the board. During that time, none of Messrs. Harkey, Ramsey, Turner, Davis or Albin was an officer or employee of ETE or any of its subsidiaries or served as an officer of any company with respect to which any of ETE's executive officers served on such company's board of directors. Mr. Davis, who resigned from the board of directors of our General Partner in February 2013, formerly served as Co-Chief Executive Officer and Co-Chairman of the board of directors of the General Partner of ETP until 2007.

In February 2013, Messrs. Harkey and Ramsey were appointed to the Compensation Committee.

Report of Compensation Committee

The board of directors of our General Partner has reviewed and discussed the section entitled "Compensation Discussion and Analysis" with the management of ETE. Based on this review and discussion, we have recommended 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 LE GP, LLC,
general partner of Energy Transfer Equity, L.P.

John D. Harkey, Jr.
Matthew S. Ramsey

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.

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 ($) (3)	Total ($)
ETE Officers:									
John W. McReynolds President	2013	$ 560,577	$ 700,721	$ —	$ —	$ —	$ —	$ 13,856	$ 1,275,154
	2012	550,000	522,500	—	—	—	—	13,834	1,086,334
	2011	550,000	550,000	—	—	—	—	12,795	1,112,795
Jamie Welch Group Chief Financial Officer and Head of Business Development	2013	272,885	550,000	44,427,760	—	—	—	180	45,250,825
ETP Officers:									
Kelcy L. Warren [(4)] Chief Executive Officer	2013	5,814	—	—	—	—	—	—	5,814
	2012	3,700	—	—	—	—	—	—	3,700
	2011	3,240	—	—	—	—	—	—	3,240
Martin Salinas, Jr. Chief Financial Officer	2013	437,019	524,423	1,861,698	—	—	56,036	26,136	2,905,312
	2012	392,750	375,000	755,515	—	—	23,261	26,140	1,572,666
	2011	360,532	400,000	1,128,500	—	—	(6,462)	25,020	1,907,590
Marshall S. (Mackie) McCrea, III President and Chief Operating Officer	2013	772,115	1,080,961	6,715,336	—	—	—	13,323	8,581,735
	2012	690,000	700,000	1,510,985	—	—	—	12,802	2,913,787
	2011	615,049	750,000	9,542,520	—	—	—	12,972	10,920,541
Thomas P. Mason Senior Vice President, General Counsel and Secretary	2013	517,308	646,635	2,308,057	—	—	—	36,923	3,508,923
	2012	466,424	500,000	1,359,900	—	—	—	35,998	2,362,322
	2011	432,901	750,000	1,805,600	—	—	—	32,590	3,021,091
Richard Cargile President of Midstream Operations	2013	331,250	305,000	535,800	—	—	83,943	13,323	1,269,316
	2012	237,500	230,000	1,379,880	—	—	3,534	12,279	1,863,193

(1) The discretionary cash bonus amounts for named executive officers for 2013 reflect cash bonuses approved by the ETE and ETP Compensation Committees in February 2014 that are expected to be paid in March 2014.

(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 9 to our consolidated financial statements for additional assumptions underlying the value of the equity awards.

(3) The amounts reflected for 2013 in this column include (i) matching contributions to the 401(k) plan made by ETE on behalf of the named executive officer of $12,212 for Mr. McReynolds, (ii) contributions to the 401(k) plan made by ETP on behalf of the named executive officers of $9,327 for Mr. Salinas and $12,750 each for Messrs. McCrea, Mason and Cargile, (iii) expenses paid by us for housing for Messrs. Salinas and Mason near our executive office in Dallas, and (iv) 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 (#) (1)	All Other Option Awards: Number of Securities Underlying Options (#)	Exercise or Base Price of Option Awards ($ / Unit)	Grant Date Fair Value of Unit Awards (2)
ETE Officers:					
ETE Unit Awards:					
John W. McReynolds	N/A	—	—	$ —	$ —
Class D Units:					
Jamie Welch(3)	12/23/2013	1,540,000	—	—	43,649,800
ETP Unit Awards:					
Jamie Welch	12/30/2013	6,900	—	—	389,160
Regency Unit Awards:					
Jamie Welch	1/3/2014	15,000			388,800
ETP Officers:					
ETP Unit Awards:					
Kelcy L. Warren	N/A	—	—	—	—
Martin Salinas, Jr.	12/30/2013	16,724	—	—	943,234
Marshall S. (Mackie) McCrea, III	12/30/2013	69,375	—	—	3,912,750
Thomas P. Mason	12/30/2013	40,923	—	—	2,308,057
Richard Cargile	12/30/2013	9,500	—	—	535,800
Sunoco Logistics Unit Awards:					
Martin Salinas, Jr.	12/5/2013	6,550	—	—	445,400
	1/24/2013	8,333	—	—	473,064
Marshall S. (Mackie) McCrea, III	12/5/2013	27,300	—	—	1,856,400
	1/24/2013	16,667	—	—	946,186

(1) ETE Unit amounts reflect the two-for-one split of ETE Common Units in January 2014.

(2) 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 9 to our consolidated financial statements.

(3) Mr. Welch's award consists of 1,540,000 Class D Units. As discussed above under "Compensation Discussion and Analysis – ETE Equity Awards," Mr. Welch was originally granted an award of ETE Common Units in April 2013; however, the award was subsequently rescinded and replaced with a new grant of 1,540,000 Class D Units in December 2013.

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

Name	Grant Date (1)	Unit Awards: Equity Incentive Plan Awards: Number of Units That Have Not Vested/Converted (#) (1) (2)	Unit Awards: Equity Incentive Plan Awards: Market or Payout Value of Units That Have Not Vested/Converted ($) (3)
ETE Officers:			
ETE Unit Awards:			
John W. McReynolds	2/24/2011	30,000	$ 1,226,100
	12/29/2009	12,000	490,440
Class D Units:			
Jamie Welch	12/23/2013	1,540,000	62,939,800
ETP Unit Awards:			
Jamie Welch	12/30/2013	6,900	395,025
Regency Unit Awards:			
Jamie Welch	1/3/2014	15,000	393,900
ETP Officers:			
ETP Unit Awards:			
Kelcy L. Warren	N/A	—	—
Martin Salinas, Jr.	12/30/2013	16,724	957,449
	1/10/2013	16,667	954,186
	12/20/2011	15,000	858,750
	12/15/2010	8,000	458,000
	12/15/2009	3,837	219,668
Marshall S. (Mackie) McCrea, III	12/30/2013	69,375	3,971,719
	1/10/2013	33,333	1,908,314
	12/20/2011	30,000	1,717,500
	5/2/2011	54,400	3,114,400
	1/14/2011	100,000	5,725,000
	12/15/2009	4,000	229,000
Thomas P. Mason	12/30/2013	40,923	2,342,842
	1/10/2013	30,000	1,717,500
	12/20/2011	24,000	1,374,000
	12/15/2010	8,000	458,000
	12/15/2009	3,637	208,218
Richard Cargile	12/30/2013	9,500	543,875
	1/10/2013	12,000	687,000
	3/14/2012	10,800	618,300
Sunoco Logistics Unit Awards:			
Martin Salinas, Jr.	12/5/2013	6,550	494,394
	1/24/2013	6,666	503,150
Marshall S. (Mackie) McCrea, III	12/5/2013	27,300	2,060,604
	1/24/2013	13,333	1,006,375

(1) ETE unit awards outstanding to Mr. McReynolds vest in December of each year through 2015 for awards granted in 2011 and in 2014 for awards granted in 2009. Class D Unit awards outstanding to Mr. Welch are eligible for conversion at a rate of 30% in March 2015 and 70% in March 2018, subject in each case to (i) Mr. Welch being in Good Standing with ETE (as defined in the Class D Unit Agreement) and (ii) there being a sufficient amount of gain available (based on the ETE partnership agreement) to be allocated to the Class D Units being converted so as to cause the capital account of each such unit to equal the capital account of an ETE Common Unit on the conversion date. ETP common unit awards outstanding to Messrs. Welch, Salinas, McCrea, Mason and Cargile vest as follows:

- at a rate of 60% in December 2016 and 40% in December 2018 for awards granted in December 2013;
- 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; and
- in December 2014 for awards granted in December 2009.

Regency common unit awards outstanding to Mr. Welch vest at as follows:

- at a rate of 60% in December 2016 and 40% in December 2018 for awards granted in January 2014.

Sunoco Logistics common unit awards outstanding to Messrs. Salinas and McCrea vest as follows:

- ratably in December of each year through 2018 for awards granted in December 2013; and
- ratably in December of each year through 2017 for awards granted in January 2013.

(2) ETE Unit amounts reflect the two-for-one split of ETE Common Units in January 2014.

(3) Market value was computed as the number of unvested awards (or units not converted in the case of Class D Units) as of December 31, 2013 multiplied by the closing price of ETP's common units or Sunoco Logistics' common units, accordingly, for ETP officers and ETE's Common Units or Regency's common units, accordingly, for ETE officers on December 31, 2013.

Option Exercises and Units Vested Table

	Unit Awards	
Name	**Number of Units Acquired on Vesting (#) (1)**	**Value Realized on Vesting ($) (1)**
ETE Officers:		
ETE Unit Awards:		
John W. McReynolds	42,000	$ 1,376,610
Class D Units:		
Jamie Welch	—	—
ETP Officers:		
ETP Unit Awards:		
Kelcy L. Warren	—	—
Martin Salinas, Jr.	16,837	908,053
Marshall S. (Mackie) McCrea, III	95,200	5,134,326
Thomas P. Mason	29,637	1,577,493
Richard Cargile	3,600	194,155
Sunoco Logistics Unit Awards:		
Martin Salinas, Jr.	1,667	114,456
Marshall S. (Mackie) McCrea, III	3,334	228,912

(1) ETE Unit amounts reflect the two-for-one split of ETE Common Units in January 2014. Amounts presented represent the number of unit awards vested during 2013 and the value realized upon vesting of these awards, which is calculated as the number of units vested multiplied by the applicable closing market price of ETP common units, Sunoco Logistics common units or ETE Common Units, accordingly, upon the vesting date.

We have not issued option awards.

Nonqualified Deferred Compensation Table

Name	Executive Contributions in Last FY[1] ($)	Registrant Contributions in Last FY ($)	Aggregate Earnings in Last FY[1] ($)	Aggregate Withdrawals/Distributions ($)	Aggregate Balance at Last FYE[1] ($)
ETE Officers:					
John W. McReynolds	$ —	$ —	$ —	$ —	$ —
Jamie Welch	—	—	—	—	—
ETP Officers:					
Kelcy L. Warren	—	—	—	—	—
Martin Salinas, Jr.	44,610	—	56,036	—	303,495
Marshall S. (Mackie) McCrea, III	—	—	—	—	—
Thomas P. Mason	—	—	—	—	—
Richard Cargile	327,964	—	83,943	—	512,779

(1) The executive contributions and aggregate earnings reflected above for Messrs. Salinas and Cargile are included in total compensation in the "Summary Compensation Table"; the remainder of the aggregate balance at last fiscal year end was reported as compensation in previous fiscal years.

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 the Energy Transfer Equity, L.P. Long-Term Incentive Plan will automatically become vested upon a change of control, which is generally defined as the occurrence of one or more of the following events: (i) any person or group becomes the beneficial owner of 50% or more of the voting power or voting securities of ETE or its general partner; (ii) LE GP, LLC or an affiliate of LE GP, LLC ceases to be the general partner of ETE; or (iii) the sale or other disposition, including by liquidation or dissolution, of all or substantially all of the assets of ETE in one or more transactions to anyone other than an affiliate of ETE.

The Class D Unit Agreement between ETE and Mr. Welch contains change of control provisions that are similar to those in the Energy Transfer Equity, L.P. Long-Term Incentive Plan. Thus, under the terms of the Class D Unit Agreement, the Class D Units will convert to ETE Common Units and the requirement of Good Standing will cease to exist upon the occurrence of one or more of the change of control events described above.

As discussed in our Compensation Discussion and Analysis above, any unvested equity awards granted pursuant to ETP's 2004 Unit Plan will automatically become vested upon a change of control. Assuming that a change of control occurred on December 31, 2013, the fair value of the unvested awards granted pursuant to ETP's 2004 Unit Plan as of December 31, 2013 was $458,000 for Mr. Mason. 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 ETP Compensation Committee, this discussion assumes a scenario in which the ETP Compensation Committee does not exercise such discretion.

While any individual award agreement may contain a modified definition, a change of control is generally defined under ETP's 2004 Unit Plan as the occurrence of any of the following events: (i) ETP GP ceases to be ETP's 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. Under the 2008 Incentive Plan, a "change of control" is generally defined as the occurrence of one or more of the following events: (i) any person or group becomes the beneficial owner of 50% or more of ETP's voting power or voting securities; (ii) the complete liquidation of either ETP LLC, ETP GP, or ETP; (iii) the sale of all or substantially all of ETP GP's or ETP's assets to anyone other than ETP, ETP GP or one of ETP's affiliates; or (iv) a person other than ETP LLC, ETP GP or one of their affiliates becomes ETP's general partner.

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 of 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 of control is generally defined in the DC Plan as any change of control event within the meaning of Treasury Regulation Section 1.409A-3(i)(5).

Director Compensation

Directors of LE GP, LLC who are employees of the LE GP, LLC, ETP GP or any of their subsidiaries are not eligible for director compensation. In 2013, the compensation arrangements for outside directors include a $50,000 annual retainer for services on the board and an annual retainer ($10,000 or $15,000 in the case of the chairman) and meeting attendance fees ($1,200) for services on the Audit Committee. In connection with the sale of Holdco to ETP and the ETE Common Unit Repurchase Program, the Board of LE GP, LLC appointed a conflicts committee consisting of Messrs. Harkey, Ramsey, and Turner and for their service, each received an aggregate fee of $37,000. In connection with the sale of SUGS to Regency, the Board of LE GP, LLC appointed a conflicts committee consisting of Messrs. Ramsey and Turner, and for their service, each received a fee of $5,000.

The outside directors of LE GP, LLC are also entitled to an annual award under the Energy Transfer Equity, L.P. Long-Term Incentive Plan equal to an aggregate of $100,000 divided by the closing price of ETE Common Units on the date of grant. These ETE Common Units will vest 60% after the third year and the remaining 40% after the fifth year after the grant date. The compensation expense recorded is based on the grant-date market value of the ETE Common Units and is recognized over the vesting period. Distributions are paid during the vesting period.

The ETP Compensation Committee periodically reviews and makes recommendations regarding the compensation of the directors of ETP's General Partner. In 2013, non-employee directors will receive an annual fee of $50,000 in cash. Additionally, the Chairman of ETP's audit committee receives an annual fee of $15,000 and the members of ETP's Audit Committee receive an annual fee of $10,000. The Chairman of the ETP Compensation Committee receives an annual fee of $7,500 and the members of the ETP Compensation Committee receive an annual fee of $5,000. In 2013, members of the ETP Conflicts Committee received cash payments on a to-be-determined basis for each ETP Conflicts Committee assignment. For their service on the ETP Conflicts Committee during 2013, Messrs. Collins, Grimm and Skidmore each received additional compensation of $10,000. ETP's employee directors, including Messrs. Warren, McCrea and Welch, do not receive any fees for service as directors. In addition, the non-employee directors participate in ETP's 2008 Incentive Plan. Each director of ETP's General Partner 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 of ETP's General Partner 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. In 2014 and beyond, non-employee ETP directors will receive annual grants of restricted ETP common units equal to an aggregate of $100,000 divided by the closing price of ETP's common units on the date of grant. Beginning in 2013, the ETP common units granted to non-employee directors will vest 60% after the third year and the remaining 40% after the fifth year after the grant date. Previously, vesting was ratable over three years.

The compensation paid to the non-employee directors of our General Partner in 2013 is reflected in the following table:

Name	Fees Paid in Cash ($) (1)	Unit Awards ($) (2)	All Other Compensation ($)	Total ($)
John D. Harkey, Jr.				
As ETE director	$ 110,975	$ 100,027	$ —	$ 211,002
As Regency director	74,900	279,225	—	354,125
Matthew S. Ramsey	109,725	100,027	—	209,752
K. Rick Turner	105,975	100,027	—	206,002

(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 ETE Common Units or Regency common units, accordingly, as of the grant date.

As of December 31, 2013, Messrs. Harkey and Turner each had 4,776 unvested ETE restricted units outstanding and Mr. Ramsey had 4,028 unvested ETE restricted units outstanding. As of December 31, 2013, Mr. Harkey had 15,334 unvested Regency restricted units outstanding.

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

Equity Compensation Plan Information

At the time of our initial public offering, we adopted the Energy Transfer Equity, L.P. Long-Term Incentive Plan for the employees, directors and consultants of our General Partner and its affiliates who perform services for us. The long-term incentive plan provides for the following five types of awards: restricted units, phantom units, unit options, unit appreciation rights and distribution equivalent rights. The long-term incentive plan limits the number of units that may be delivered pursuant to awards to three million units. Units withheld to satisfy exercise prices or tax withholding obligations are available for delivery pursuant to other awards. The plan is administered by the compensation committee of the board of directors of our General Partner.

The following table sets forth in tabular format, a summary of our equity plan information as of December 31, 2013:

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	—	$ —	—
Equity compensation plans not approved by security holders:			
Energy Transfer Equity, L.P. Long-Term Incentive Plan	—	—	5,693,789
Class D Unit Agreement	1,540,000	$ —	—
Total	1,540,000	$ —	5,693,789

Energy Transfer Equity, L.P. Units

The following table sets forth certain information as of February 21, 2014, 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)	Percent of Class
Common Units	Ray C. Davis (3)	33,604,950	6.0%
	John D. Harkey, Jr. (4)	61,158	*
	John W. McReynolds (5)	12,499,944	2.2%
	Kelcy L. Warren (6)	89,985,112	16.1%
	Jamie Welch (7)	1,540,000	*
	Marshall S. (Mackie) McCrea, III	1,782,614	*
	Matthew S. Ramsey	23,820	*
	K. Rick Turner	173,286	*
	All Directors and Executive Officers as a group (7 persons)	106,065,934	18.9%

* Less than 1%

(1) The address for Mr. Davis is 5950 Sherry Lane, Dallas, Texas 75225. Messrs. Warren, Welch, McReynolds, Harkey, McCrea, Ramsey and Turner is 3738 Oak Lawn Avenue, Dallas, Texas 75219.

(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 days. Nature of beneficial ownership is direct with sole investment and disposition power unless otherwise noted.

(3) Includes 20,846 units held by Avatar Holdings LLC, 11,371,340 units held by Avatar ETC Stock Holdings LLC, 1,434,474 units held by Avatar Investments LP, 48,834 units held by Avatar Stock Holdings LLC and 390,984 units held by RCD Stock Holdings LLC, all of which entities are owned or controlled by Mr. Davis. Also includes 6,446,010 units held by a remainder trust for Mr. Davis' spouse and 4,351,688 units held by two trusts for the benefit of Mr. Davis' grandchildren,

for which Mr. Davis serves as trustee. Mr. Davis shares voting and dispositive power with his wife with respect to 9,538,266 units held directly. Also includes 2,508 units attributable to the interest of Mr. Davis in ET Company Ltd and Three Dawaco, Inc., over which Mr. Davis exercises shared voting and dispositive power with Mr. Warren. Excludes Mr. Davis' interest in 308,538 units held by LE GP, LLC. Mr. Davis may be deemed to own units held by LE GP, LLC due to his ownership of 18.8% of its member interests. The voting and disposition of these units is directly controlled by the board of directors of LE GP, LLC. Mr. Davis disclaims beneficial ownership of units owned by LE GP LLC other than to the extent of his interest in such entity. Mr. Davis is a former executive officer of ETP and former director of our General Partner.

(4) Includes 50,000 units held by the Katemcy Trust.

(5) Includes 7,245,204 units held by McReynolds Energy Partners L.P. and 5,043,140 units held by McReynolds Equity Partners L.P., the general partners of which are owned by Mr. McReynolds. Mr. McReynolds disclaims beneficial ownership of units owned by such limited partnerships other than to the extent of his interest in such entities.

(6) Includes 38,351,100 units held by Kelcy Warren Partners, L.P. and 3,479,950 units held by Kelcy Warren Partners II, L.P., the general partners of which are owned by Mr. Warren. Also includes 35,926,908 units held by Seven Bridges Holdings, LLC, of which Mr. Warren is a member. Also includes 2,506 units attributable to the interest of Mr. Warren in ET Company Ltd and Three Dawaco, Inc., over which Mr. Warren exercises shared voting and dispositive power with Ray Davis. Also includes 308,538 units held by LE GP, LLC. Mr. Warren may be deemed to own units held by LE GP, LLC due to his ownership of 81.2% of its member interests. The voting and disposition of these units is directly controlled by the board of directors of LE GP, LLC. Mr. Warren disclaims beneficial ownership of units owned by LE GP, LLC other than to the extent of his interest in such entity.

(7) Represents Class D Units convertible into 1,540,000 Common Units. The Class D Units have voting and distribution rights equal to Common Units and are therefore included in this table.

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

At December 31, 2013, our equity interests in ETP and Regency consisted of 100% of the respective general partner interest and IDRs, as well as the following:

	ETP	Regency
Units held by wholly-owned subsidiaries:		
Common units	49,551,069	26,266,791
ETP Class H units	50,160,000	—
Units held by less than wholly-owned subsidiaries:		
Common units	—	31,372,419
Regency Class F units	—	6,274,483

The Parent Company's principal sources of cash flow are derived from its direct and indirect investments in the limited partner and general partner interests in ETP and Regency, both of which are publicly traded master limited partnerships engaged in diversified energy-related services.

ETP and Regency are required by their respective partnership agreements to distribute all cash on hand at the end of each quarter, less appropriate reserves determined by the board of directors of their respective general partners.

Immediately following the closing of ETP'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, ETP 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 ETP in exchange for 90.7 million ETP Class F Units representing limited partner interests in ETP. The ETP Class F Units were 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 ETP Class F Unit per year, which is the current level. In April 2013, all of the outstanding ETP Class F Units were exchanged for ETP Class G Units on a one-for-one basis. The ETP Class G Units have terms that are substantially the same as the ETP Class F Units, with the principal difference between the ETP Class G Units and the ETP Class F Units being that allocations of depreciation and amortization to the ETP Class G Units for tax purposes are based on a predetermined percentage and are not contingent on whether ETP has net income or loss.

On April 30, 2013, Southern Union completed its contribution to Regency of all of the issued and outstanding membership interest in Southern Union Gathering Company, LLC, and its subsidiaries, including SUGS (the "SUGS Contribution"). The general partner and IDRs of Regency are owned by ETE. The consideration paid by Regency in connection with this transaction consisted of (i) the issuance of approximately 31.4 million Regency common units to Southern Union, (ii) the issuance of approximately 6.3 million Regency Class F units to Southern Union, (iii) the distribution of $463 million in cash to Southern Union, net of closing adjustments, and (iv) the payment of $30 million in cash to a subsidiary of ETP. The Regency Class F units 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.

On April 30, 2013, ETP acquired ETE's 60% interest in Holdco for approximately 49.5 million of newly issued ETP Common Units and $1.40 billion in cash, less $68 million of closing adjustments (the "Holdco Acquisition"). As a result, ETP now owns 100% of Holdco. ETE, which owns the general partner and IDRs of ETP, agreed to forego incentive distributions on the newly issued ETP units for each of the first eight consecutive quarters beginning with the quarter in which the closing of the transaction occurred and 50% of incentive distributions on the newly issued ETP units for the following eight consecutive quarters. ETP controlled Holdco prior to this acquisition; therefore, the transaction did not constitute a change of control.

Pursuant to an Exchange and Redemption Agreement previously entered into between ETP, ETE and ETE Holdings, ETP redeemed and cancelled 50.2 million of its ETP Common Units representing limited partner interests (the "Redeemed Units") owned by ETE Holdings on October 31, 2013 in exchange for the issuance by ETP to ETE Holdings of a new class of limited partner interest in ETP (the "ETP Class H Units"), which are generally entitled to (i) allocations of profits, losses and other items from ETP corresponding to 50.05% of the profits, losses, and other items allocated to ETP by Sunoco Partners with respect to the IDRs and general partner interest in Sunoco Logistics held by Sunoco Partners, (ii) distributions from available cash at ETP for each quarter equal to 50.05% of the cash distributed to ETP by Sunoco Partners with respect to the IDRs and general partner interest in Sunoco Logistics held by Sunoco Partners for such quarter and, to the extent not previously distributed to holders of the ETP Class H Units, for any previous quarters and (iii) incremental additional cash distributions in the aggregate amount of $329 million, to be payable by ETP to ETE Holdings over 15 quarters, commencing with the quarter ended September 30, 2013 and ending with the quarter ending March 31, 2017. The incremental cash distributions referred to in clause (iii) of the previous sentence are intended to offset a portion of the incentive distribution relinquishments previously granted by ETE to ETP in connection with the Citrus Merger, the Holdco Transaction and the Holdco Acquisition. In connection with the issuance of the ETP Class H Units, ETE and ETP also agreed to certain adjustments to the prior incentive distribution relinquishments in order to ensure that the incentive distribution relinquishments are fixed amounts for each quarter to which the incentive distribution relinquishments are in effect.

On February 19, 2014, ETE and ETP completed the transfer to ETE of Trunkline LNG, the entity that owns a LNG regasification facility in Lake Charles, Louisiana, from ETP in exchange for the redemption by ETP of 18.7 million. The transaction was effective as of January 1, 2014.

In connection with ETE's acquisition of Trunkline LNG, ETP agreed to continue to provide management services for ETE through 2015 in relation to both Trunkline LNG's regasification facility and the development of a liquefaction project at Trunkline LNG's facility, for which ETE has agreed to pay incremental management fees to ETP of $75 million per year for the years ending December 31, 2014 and 2015. ETE also agreed to provide additional subsidies to ETP through the relinquishment of future incentive distributions of $50 million, $50 million, $45 million, and $35 million during the years ended December 31, 2016, 2017, 2018 and 2019, respectively.

Mr. McCrea, a current director of LE GP, LLC, our General Partner, is also a director and executive officer of ETP GP. In addition, Mr. Warren, the Chairman of our Board of Directors, is also a director and executive officer of ETP GP.

For a discussion of director independence, see Item 10. "Directors, Executive Officers and Corporate Governance."

As a policy matter, our 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 contractually-limited fiduciary duties to the Unitholders. The partnership agreement of ETE provides that any matter approved by the Conflicts Committee will be conclusively deemed to be fair and reasonable to

ETE, approved by all the partners of ETE and not a breach by the General Partner or its Board of Directors of any duties they may owe ETE or the Unitholders (see “Risks Related to Conflicts of Interest” in Item 1A. Risk Factors” in this annual report).

The Parent Company has agreements with subsidiaries to provide or receive various general and administrative services. The Parent Company pays ETP to provide services on its behalf and the behalf of other subsidiaries of the Parent Company. The Parent Company receives management fees from certain of its subsidiaries, which include the reimbursement of various general and administrative services for expenses incurred by ETP on behalf of those subsidiaries. All such amounts have been eliminated in our consolidated financial statements.

ETP has an operating lease agreement with Messrs. Davis and Warren, the former owners of ETG, which ETP acquired in 2009. Prior to the consummation of the transaction, the committee made the determination that both the sale of ETG to ETP and the terms of the operating lease between ETP and Messrs. Davis and Warren were fair and reasonable to ETP. See discussion in Note 14 to our consolidated financial statements.

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,	
	2013	2012
Audit fees [(1)]	$ 8,099,000	$ 5,869,000
Audit-related fees [(2)]	682,300	25,000
Tax fees [(3)]	—	1,525
Total	$ 8,781,300	$ 5,895,525

(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 controls over financial reporting.

(2) Includes fees in 2013 for financial statement audits of subsidiary entities in connection with the contribution of SUGS from Southern Union to Regency and the sale of Southern Union’s distribution operations. Includes fees in 2013 for audits of Sunoco’s benefit plans. Includes fees in 2013 and 2012 in connection with the service organization control report on Southern Union’s centralized data center.

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

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.

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.

(b) Exhibits - see Index to Exhibits set forth on page E-1.

(c) Financial statements of affiliates whose securities are pledged as collateral - See Index to Financial Statements on page S-1.

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 EQUITY, L.P.

By: LE GP, LLC,
its general partner

Date: February 27, 2014

By: /s/ Jamie Welch
Jamie Welch
Group Chief Financial 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/ John W. McReynolds John W. McReynolds	Director and President (Principal Executive Officer)	February 27, 2014
/s/ Jamie Welch Jamie Welch	Director and Group Chief Financial Officer and Head of Business Development (Principal Financial and Accounting Officer)	February 27, 2014
/s/ Kelcy L. Warren Kelcy L. Warren	Director and Chairman of the Board	February 27, 2014
/s/ John D. Harkey John D. Harkey	Director	February 27, 2014
/s/ Marshall S. McCrea, III Marshall S. McCrea, III	Director	February 27, 2014
/s/ Matthew S. Ramsey Matthew S. Ramsey	Director	February 27, 2014
/s/ K. Rick Turner K. Rick Turner	Director	February 27, 2014

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	
2.1	General Partner Purchase Agreement, dated May 10, 2010, by and among Regency GP Acquirer, L.P., Energy Transfer Equity, L.P. and ETE GP Acquirer LLC (incorporated by reference to Exhibit 2.1 of Form 8-K/A, file No. 1-32740, filed May 13, 2010)
2.2	Contribution Agreement, dated May 10, 2010, by and among Energy Transfer Equity, L.P., Regency Energy Partners LP and Regency Midcontinent Express LLC (incorporated by reference to Exhibit 2.3 of Form 8-K/A, file No. 1-32740, filed May 13, 2010)
2.3	Agreement and Plan of Merger, by and among, Energy Transfer Equity, L.P., Sigma Acquisition Corporation, and Southern Union Company, dated as of June 15, 2011 (incorporated by reference to Exhibit 2.1 of Form 8-K, file No. 1-32740, filed June 20, 2011)
2.4	Agreement and Plan of Merger, by and among, Energy Transfer Equity, L.P., Sigma Acquisition Corporation, and Southern Union Company, dated as of June 15, 2011, as Amended and Restated as of July 4, 2011 (incorporated by reference to Exhibit 2.1 of Form 8-K, file No. 1-32740, filed July 5, 2011)
2.4.1	Support Agreement dated June 15, 2011 by and among Energy Transfer Equity, L.P., Sigma Acquisition Corporation, and certain stockholders of Southern Union Company (incorporated by reference to Exhibit 10.1 of Form 8-K, file No. 1-32740, filed July 5, 2011)
2.5	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 as of July 19, 2011 (incorporated by reference to Exhibit 2.2 of Form 8-K, file No. 1-32740, filed July 20, 2011)
2.6	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 (incorporated by reference to Exhibit 2.1 of Form 8-K, file No. 1-32740, filed September 15, 2011)
2.7	Amendment No. 1, dated as of September 14, 2011, to 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. (incorporated by reference to Exhibit 2.2 of Form 8-K, file No. 1-32740, filed September 15, 2011)
2.8	Amendment No. 2, dated as of March 23, 2012, to Amended and Restated Agreement and Plan of Merger, by and among Energy Transfer Equity, L.P., Energy Transfer Partners, L.P., Citrus ETP Acquisition, L.L.C, Southern Union Company and CrossCountry Energy, LLC, dated as of July 19, 2011 (incorporated by reference to Exhibit 2.1 of Form 8-K, file No. 1-32740, filed March 28, 2012)
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. (incorporated by reference to Exhibit 2.1 of Form 8-K, file No. 1-32740, filed May 1, 2012)
2.10	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 (incorporated by reference to Exhibit 2.1 of Form 8-K, file No. 1-32740, filed June 20, 2012)
2.11	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. (incorporated by reference to Exhibit 2.2 of Form 8-K, file No. 1-32740, filed June 20, 2012)
2.12	Redemption and Transfer Agreement by and between Energy Transfer Equity, L.P. and Energy Transfer Partners, L.P. dated November 19, 2013 (incorporated by reference to Exhibit 2.1 of Form 8-K, file No. 1-32740, filed November 21, 2013)
3.1	Certificate of Conversion of Energy Transfer Company, L.P. (incorporated by reference to Exhibit 3.1 of Form S-1, file No. 333-128097, filed September 2, 2005)
3.2	Certificate of Limited Partnership of Energy Transfer Equity, L.P. (incorporated by reference to Exhibit 3.2 of Form S-1, file No. 333-128097, filed September 2, 2005)

Exhibit Number	
3.3	Third Amended Restated Agreement of Limited Partnership of Energy Transfer Equity, L.P. (incorporated by reference to Exhibit 3.1 of Form 8-K, file No. 1-32740, filed February 14, 2006)
3.3.1	Amendment No. 1 to Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Equity, L.P. (incorporated by reference to Exhibit 3.3.1 of Form 10-K, file No. 1-32740, filed August 31, 2006)
3.3.2	Amendment No. 2 to Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Equity, L.P. (incorporated by reference to Exhibit 3.3.2 of Form 8-K, file No. 1-32740, filed November 13, 2007)
3.3.3	Amendment No. 3 to Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Equity, L.P. (incorporated by reference to Exhibit 3.1 of Form 8-K, file No. 1-32740, filed June 2, 2010)
3.4	Certificate of Conversion of LE GP, LLC (incorporated by reference to Exhibit 3.4 of Form S-1, file No. 333-128097, filed September 2, 2005)
3.5	Certificate of Formation of LE GP, LLC (incorporated by reference to Exhibit 3.5 of Form S-1, file No. 333-128097, filed September 2, 2005)
3.6	Amended and Restated Limited Liability Company Agreement of LE GP, LLC (incorporated by reference to Exhibit 3.6.1 of Form 8-K, file No. 1-32740, filed May 8, 2007)
3.6.1	Amendment No. 1 to Amended and Restated Limited Liability Company Agreement of LE GP, LLC (incorporated by reference to Exhibit 3.1 of Form 8-K, file No. 1-32740, filed December 23, 2009)
3.7	Second Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.) (incorporated by reference to Exhibit 3.1 of Form 8-K, file No. 1-11727, filed July 28, 2009)
3.8	Amended Certificate of Limited Partnership of Energy Transfer Partners, L.P. (incorporated by reference to Exhibit 3.3 of Form 10-Q, file No. 1-11727, filed February 29, 2004)
3.9	Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners GP, L.P. (incorporated by reference to Exhibit 3.5 of Form 10-Q, file No. 1-11727, filed May 31, 2007)
3.10	Third Amended and Restated Limited Liability Company Agreement of Energy Transfer Partners, L.L.C. (incorporated by reference to Exhibit 3.6 of Form 10-Q, file No. 1-11727, filed May 31, 2007)
3.10.1	Fourth Amended and Restated Limited Liability Company Agreement of Energy Transfer Partners, L.L.C. (incorporated by reference to Exhibit 3.6 of Form 8-K, file No. 1-11727, filed August 10, 2010)
3.11	Certificate of Formation of Energy Transfer Partners, L.L.C. (incorporated by reference to Exhibit 3.13 of Form S-1/A, file No. 333-128097, filed December 20, 2005)
3.11.1	Certificate of Amendment of Energy Transfer Partners, L.L.C. (incorporated by reference to Exhibit 3.13.1 of Form S-1/A, file No. 333-128097, filed December 20, 2005)
3.12	Restated Certificate of Limited Partnership of Energy Transfer Partners GP, L.P. (incorporated by reference to Exhibit 3.14 of Form S-1/A, file No. 333-128097, filed December 20, 2005)
3.13	Second Amendment to Amended and Restated Limited Liability Company Agreement of Regency GP, L.L.C. (incorporated by reference to Exhibit 3.2 of Form 8-K, file No. 1-32740, filed August 10, 2010)
3.14	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 (incorporated by reference to Exhibit 3.1 of Form 8-K, file No. 1-32740, filed March 28, 2012)
3.15	Amendment No. 2, dated March 26, 2012, to Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners GP, L.P., dated April 17, 2007 (incorporated by reference to Exhibit 3.2 of Form 8-K, file No. 1-32740, filed March 28, 2012)
3.16	Amendment No. 1, dated March 26, 2012, to the Fourth Amended and Restated Agreement of Limited Liability Company Agreement of Energy Transfer Partners, L.L.C., dated August 10, 2010 (incorporated by reference to Exhibit 3.3 of Form 8-K, file No. 1-32740, filed March 28, 2012)
3.17	Amendment No. 4, dated April 30, 2013, to the Second Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P., as amended (incorporated by reference to Exhibit 3.1 of Form 8-K, file No. 1-32740, filed May 1, 2013)
4.1	Indenture dated January 18, 2005 among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 of Form 8-K, file No. 1-11727, filed January 19, 2005)
4.2	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 (incorporated by reference to Exhibit 4.2 of Form 8-K, file No. 1-11727, filed January 19, 2005)
4.3	Second Supplemental Indenture dated as of February 24, 2005 to Indenture dated as of January 18, 2005 (incorporated by reference to Exhibit 10.45 of Form 10-Q, file No. 1-11727, filed February 28, 2005)

Exhibit Number	
4.4	Notation of Guaranty (incorporated by reference to Exhibit 10.5 of Form 10-Q, file No. 1-11727, filed February 28, 2005)
4.5	Registration Rights Agreement dated January 18, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and the initial purchasers party thereto (incorporated by reference to Exhibit 4.3 of Form 8-K, file No. 1-11727, filed January 19, 2005)
4.6	Joinder to Registration Rights Agreement dated February 24, 2005, among Energy Transfer Partners, L.P., the Subsidiary Guarantors and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 10.39.1 of Form 10-Q, file No. 1-11727, filed February 28, 2005)
4.7	Third Supplemental Indenture dated July 29, 2005, to Indenture dated January 18, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors named therein, and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 of Form 8-K, file No. 1-11727, filed August 2, 2005)
4.8	Registration Rights Agreement dated July 29, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors named therein, and the initial purchasers party thereto (incorporated by reference to Exhibit 4.2 of Form 8-K, file No. 1-11727, filed August 2, 2005)
4.9	Form of Senior Indenture of Energy Transfer Partners, L.P. (incorporated by reference to Exhibit 4.9 of Form 10-K/A, file No. 1-11727, filed August 31, 2005)
4.10	Form of Subordinated Indenture of Energy Transfer Partners, L.P. (incorporated by reference to Exhibit 4.10 of Form 10-K/A, file No. 1-11727, filed August 31, 2005)
4.11	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 (incorporated by reference to Exhibit 4.13 of Form 10-K, file No. 1-11727, filed August 31, 2006)
4.12	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 (incorporated by reference to Exhibit 4.1 of Form 8-K, file No. 1-11727, filed October 25, 2006)
4.13	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 (incorporated by reference to Exhibit 4.2 of Form 8-K, file No. 1-11727, filed March 28, 2008)
4.14	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 (incorporated by reference to Exhibit 4.2 of Form 8-K, file No. 1-11727, filed December 23, 2008)
4.15	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 (incorporated by reference to Exhibit 4.2 of Form 8-K, file No. 1-11727, filed April 7, 2009)
4.16	Energy Transfer Partners, L.P. 2008 Long-Term Incentive Plan (incorporated by reference to Exhibit A of Form DEF 14A, file No. 1-11727, filed November 21, 2008)
4.17	Registration Rights Agreement by and among Energy Transfer Equity, L.P. and Regency GP Acquirer, L.P., dated as of May 26, 2010 (incorporated by reference to Exhibit 4.14 of Form 8-K, file No. 1-32740, filed June 2, 2010)
4.18	Indenture dated September 20, 2010 between Energy Transfer Equity, L.P. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.14 of Form 8-K, file No. 1-32740, filed September 20, 2010)
4.19	First Supplemental Indenture dated September 20, 2010 between Energy Transfer Equity, L.P. and U.S. Bank National Association, as trustee (including form of the Notes) (incorporated by reference to Exhibit 4.15 of Form 8-K, file No. 1-32740, filed September 20, 2010)
4.20	Second Supplemental Indenture dated as of February 16, 2012, between Energy Transfer Equity, L.P., and U.S. Bank National Association (incorporated by reference to Exhibit 4.1 of Form 8-K, file No. 1-32740, filed February 17, 2012)
4.21	Third Supplemental Indenture dated April 24, 2012 to Indenture dated September 20, 2010 between Energy Transfer Equity, L.P. and US Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 of Form 10-Q, file No. 1-32740, filed August 8, 2012)
4.22	Registration Rights Agreement, dated April 30, 2013, by and between Energy Transfer Partners, L.P. and Energy Transfer Equity, L.P. (incorporated by reference to Exhibit 4.1 of Form 8-K, file No. 1-32740, filed May 1, 2013)
4.23	Fourth Supplemental Indenture dated December 2, 2013 between Energy Transfer Equity, L.P. and U.S. Bank National Association, as trustee (including form of the Notes) (incorporated by reference to Exhibit 4.2 of Form 8-K, file No. 1-32740, filed December 2, 2013)

Exhibit Number		
10.1		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 LaGrange Acquisition, L.P., as Buyer (incorporated by reference to Exhibit 10.1 of Form 8-K, file No. 1-11727, filed February 1, 2005)
10.2		Cushion Gas Litigation Agreement dated January 26, 2005, among AEP Energy Services Gas Holding Company II, L.L.C. and HPL Storage LP, as Sellers, and LaGrange 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 (incorporated by reference to Exhibit 10.2 of Form 8-K, file No. 1-11727, filed February 1, 2005)
10.3		Energy Transfer Partners, L.P. Summary of Director Compensation (incorporated by reference to Exhibit 10.45 of Form 10-K, file No. 1-11727, filed August 31, 2006)
10.4.1	+	Energy Transfer Partners, L.P. Amended and Restated 2004 Unit Plan (incorporated by reference to Exhibit 10.6.6 of Form 10-Q, file No. 1-11727, filed June 30, 2008)
10.4.2	+	Energy Transfer Partners, L.P. Amended and Restated 2008 Long Term Incentive Plan (incorporated by reference to Exhibit 10.1 of Form 8-K, file No. 1-11727, filed December 19, 2008)
10.4.3	+	Energy Transfer Partners Deferred Compensation Plan (incorporated by reference to Exhibit 10.1 of Form 8-K, file No. 1-11727, filed March 31, 2010)
10.4.4	+	Form of Grant Agreement under the Energy Transfer Partners, L.P. Amended and Restated 2004 Unit Plan and the Energy Transfer Partners, L.P. 2008 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 of Form 8-K, file No. 1-11727, filed November 1, 2004)
10.4.5	+	Energy Transfer Partners, L.P. Midstream Bonus Plan (incorporated by reference to Exhibit 10.1 of Form 8-K, file No. 1-11727, filed March 3, 2008)
10.5		Registration Rights Agreement for Limited Partner Interests of Heritage Propane Partners, L.P. (incorporated by reference to Exhibit 4.1 of Form 8-K, file No. 1-11727, filed February 4, 2002)
10.6		Unitholder Rights Agreement dated January 20, 2004, among Heritage Propane Partners, L.P., Heritage Holdings, Inc., TAAP LP and LaGrange Energy, L.P. (incorporated by reference to Exhibit 4.2 of Form 10-Q, file No. 1-11727, filed February 29, 2004)
10.7		Registration Rights Agreement for Limited Partnership Units of LaGrange Energy, L.P. (incorporated by reference to Exhibit 10.47 of Form S-1, file No. 333-128097, filed October 13, 2005)
10.8	+	Energy Transfer Equity, L.P. Long-Term Incentive Plan (incorporated by reference to Exhibit 10.25 of Form S-1, file No. 333-128097, filed December 20, 2005)
10.9	+	Form of Director and Officer Indemnification Agreement (incorporated by reference to Exhibit 10.26 of Form S-1, file No. 333-128097, filed December 20, 2005)
10.10		Second Amended and Restated Credit Agreement, dated October 27, 2011, 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 (incorporated by reference to Exhibit 10.1 of Form 8-K, file No. 1-11727, filed November 2, 2011)
10.11		Amended and Restated Credit Agreement dated July 13, 2006, between Energy Transfer Equity, L.P. and Wachovia Bank, National Association, as administrative agent, LC issuer and swingline lender, Bank of America, N.A. and Citicorp North America, Inc., as co-syndication agents, BNP Paribas and The Royal Bank of Scotland plc, as co-documentation agents, Credit Suisse Cayman Islands Branch, Deutsche Bank AG New York Branch and UBS Securities LLC, as senior managing agents, and Fortis Capital Corp, Suntrust Bank and Wells Fargo Bank, N.A., as managing agents (incorporated by reference to Exhibit 10.2 of Form 8-K, file No. 1-32740, filed July 19, 2006)
10.12		First Amendment to Amended and Restated Credit Agreement, dated November 1, 2006, among Energy Transfer Equity, L.P., as the borrower, Wachovia Bank, National Association as administrative agent, UBS Loan Finance LLC, as syndication agent, BNP Paribas, Citicorp North America, Inc. and JPMorgan Chase Bank, N.A. as co-documentation agents, and UBS Securities LLC and Wachovia Capital Markets, LLC, as joint lead arrangers and joint book managers (incorporated by reference to Exhibit 10.34 of Form 10-K, file No. 1-32740, filed August 31, 2006)
10.12.1		Second Amended and Restated Credit Agreement, dated as of May 19, 2010, among Energy Transfer Equity, L.P. as the borrower, Wells Fargo Bank, National Association, as administrative agent, Bank of America, N.A. and Citicorp North America, Inc., as co-syndication agents, BNP PARIBAS and the Royal Bank of Scotland plc, as co-documentation agents, Credit Suisse, Cayman Islands Branch, Deutsche Bank AG New York Branch, and UBS Securities LLC, as senior managing agents, Fortis Capital Corp, and Sun Trust Banks, as managing agents, and other lenders party thereto (incorporated by reference to Exhibit 10.1 of Form 8-K, file No. 1-32740, filed June 2, 2010)

Exhibit Number		
10.13		Contribution and Conveyance Agreement, dated November 1, 2006, between Energy Transfer Equity, L.P., and Energy Transfer Partners, L.P. (incorporated by reference to Exhibit 10.35 of Form 10-K, file No. 1-32740, filed August 31, 2006)
10.14		Contribution, Assumption and Conveyance Agreement, dated November 1, 2006, between Energy Transfer Equity, L.P., and Energy Transfer Investments, L.P. (incorporated by reference to Exhibit 10.36 of Form 10-K, file No. 1-32740, filed August 31, 2006)
10.15		Registration Rights Agreement, dated November 1, 2006, between Energy Transfer Partners, L.P. and Energy Transfer Equity, L.P. (incorporated by reference to Exhibit 3.1.10 of Form 8-K, file No. 1-11727, filed November 3, 2006)
10.16		Registration Rights Agreement, dated November 1, 2006, between Energy Transfer Equity, L.P. and Energy Transfer Investments, L.P. (incorporated by reference to Exhibit 10.38 of Form 10-K, file No. 1-32740, filed August 31, 2006)
10.17		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 Holding I LLC (incorporated by reference to Exhibit 10.1 of Form 8-K, file No. 1-11727, filed September 18, 2006)
10.18		Redemption Agreement, dated September 14, 2006, between Energy Transfer Partners, L.P. and CCE Holdings, LLC (incorporated by reference to Exhibit 10.2 of Form 8-K, file No. 1-11727, filed September 18, 2006)
10.19		Letter Agreement, dated September 14, 2006, between Energy Transfer Partners, L.P. and Southern Union Company (incorporated by reference to Exhibit 10.3 of Form 8-K, file No. 1-11727, filed September 18, 2006)
10.20		Registration Rights Agreement, dated November 27, 2006, by and among Energy Transfer Equity, L.P. and certain investors named therein (incorporated by reference to Exhibit 99.1 of Form 8-K, file No. 1-32740, filed November 30, 2006)
10.21	+	LE GP, LLC Outside Director Compensation Policy (incorporated by reference to Exhibit 99.1 of Form 8-K, file No. 1-32740, filed December 26, 2006)
10.22		Registration Rights Agreement, dated March 2, 2007, by and among Energy Transfer Equity, L.P. and certain investors named therein (incorporated by reference to Exhibit 99.1 of Form 8-K, file No. 1-32740, filed March 5, 2007)
10.23		Unitholder Rights and Restrictions Agreement, dated as of May 7, 2007, by and among Energy Transfer Equity, L.P., Ray C. Davis, Natural Gas Partners VI, L.P. and Enterprise GP Holdings, L.P. (incorporated by reference to Exhibit 10.45 of Form 8-K, file No. 1-32740, filed May 7, 2007)
10.24		Note Purchase Agreement, dated as of November 17, 2004, by and among Transwestern Pipeline Company, LLC and the Purchasers parties thereto (incorporated by reference to Exhibit 10.55 of Form 10-Q, file No. 1-11727, filed May 31, 2007)
10.24.1		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 (incorporated by reference to Exhibit 10.55.1 of Form 10-Q, file No. 1-11727, filed May 31, 2007)
10.25		Note Purchase Agreement, dated as of May 24, 2007, by and among Transwestern Pipeline Company, LLC and the Purchasers parties thereto (incorporated by reference to Exhibit 10.6 of Form 10-Q, file No. 1-11727, filed May 31, 2007)
10.26		Credit Agreement, dated September 20, 2010 among Energy Transfer Equity, L.P., as the borrower, Credit Suisse AG, as administrative agent and collateral agent, and the other lenders party thereto, and Credit Suisse Securities (USA) LLC, as sole lead arranger and sole book runner (incorporated by reference to Exhibit 10.1 of Form 8-K, file No. 1-32740, filed September 20, 2010)
10.27		Pledge and Security Agreement, dated September 20, 2010, by and among Energy Transfer Equity, L.P., Energy Transfer Partners, L.L.C., ETE GP Acquirer LLC, ETE Services Company, LLC, Regency GP LLC, as the grantors, and Credit Suisse AG, Cayman Islands Branch, as collateral agent for the lenders under the Credit Agreement dated September 20, 2010 (incorporated by reference to Exhibit 10.2 of Form 8-K, file No. 1-32740, filed September 20, 2010)
10.28		Amended and Restated Support Agreement dated July 4, 2011 by and among Energy Transfer Equity, L.P., Sigma Acquisition Corporation and certain stockholders of Southern Union Company (incorporated by reference to Exhibit 10.5 of Form 8-K, file No. 1-32740, filed July 5, 2011)
10.29		Second Amended and Restated Support Agreement, dated as of July 19, 2011, by and among, Energy Transfer Equity, L.P., Sigma Acquisition Corporation and certain stockholders of Southern Union Company (incorporated by reference to Exhibit 10.1 of Form 8-K, file No. 1-32740, filed July 20, 2011)
10.30		First Amendment to Credit Agreement, dated September 20, 2010 among Energy Transfer Equity, L.P., as the borrower, Credit Suisse AG, as administrative agent and collateral agent, and the other lenders party thereto, and Credit Suisse Securities (USA) LLC, as sole lead arranger and sole book runner (incorporated by reference to Exhibit 10.1.1 of Form 10-Q, file No. 1-32740, filed August 8, 2011)

Exhibit Number	
10.31	Support Agreement dated June 15, 2011 by and among Energy Transfer Equity, L.P., Sigma Acquisition Corporation, and certain stockholders of Southern Union Company (incorporated by reference to Exhibit 10.1 of Form 8-K, file No. 1-32740, filed July 5, 2011)
10.32	Senior Bridge Term Loan Credit Agreement, dated as of October 17, 2011 among Energy Transfer Equity, L.P., as the borrower, Credit Suisse AG, as administrative agent, and the other lenders party thereto, and Credit Suisse Securities (USA) LLC, as sole arranger and sole bookrunner (incorporated by reference to Exhibit 10.1 of Form 8-K, file No. 1-32740, filed October 21, 2011)
10.33	Guarantee of Collection, made as of March 26, 2012, by Citrus ETP Finance LLC, to Energy Transfer Partners, L.P. under the Indenture dated as of January 18, 2005, as supplemented by the Tenth Supplemental Indenture dated as of January 17, 2012 (incorporated by reference to Exhibit 10.1 of Form 8-K, file No. 1-32740, filed March 28, 2012)
10.34	Support Agreement, dated March 26, 2012, by and among PEPL Holdings, LLC, Energy Transfer Partners, L.P. and Citrus ETP Finance LLC (incorporated by reference to Exhibit 10.2 of Form 8-K, file No. 1-32740, filed March 28, 2012)
10.35	Senior Secured Term Loan Agreement dated March 23, 2012, by and among Energy Transfer Equity, L.P. and Credit Suisse AG, as Administrative Agent, and the other lenders from time to time party thereto (incorporated by reference to Exhibit 10.3 of Form 8-K, file No. 1-32740, filed March 28, 2012)
10.36	Amendment No. 2 to Credit Agreement dated, as of March 23, 2012, by and among Energy Transfer Equity, L.P. and Credit Suisse AG, as Administrative Agent and the other lenders party thereto (incorporated by reference to Exhibit 10.4 of Form 8-K, file No. 1-32740, filed March 28, 2012)
10.37	Letter Agreement, dated as of April 29, 2012, by and among Energy Transfer Partners, L.P. and Energy Transfer Equity, L.P. (incorporated by reference to Exhibit 10.1 of Form 8-K, file No. 1-32740, filed May 1, 2012)
10.38	Amendment No. 1 to Amended and Restated Credit Agreement dated as of September 13, 2012, between Energy Transfer Equity, L.P., several banks and other financial institutions signatories, and Credit Suisse AG, as Administrative Agent for the Lenders (incorporated by reference to Exhibit 10.1.1 of Form 10-Q, file No. 1-32740, filed November 8, 2012)
10.39	Amendment No.1 to Senior Secured Term Loan Agreement by and among Energy Transfer Equity, L.P. (the “Borrower”), the Restricted Persons party thereto, the Lenders party thereto and Credit Suisse AG, in its capacity as administrative agent for the Lenders dated as of August 2, 2012 (incorporated by reference to Exhibit 10.1 of Form 8-K, file No. 1-32740, filed August 8, 2012)
10.40	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. (incorporated by reference to Exhibit 10.1 of Form 8-K, file No. 1-32740, filed December 17, 2012)
10.41	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. (incorporated by reference to Exhibit 10.2 of Form 8-K, file No. 1-32740, filed December 17, 2012)
10.42	First Amendment, dated April 30, 2013, to the Services Agreement, effective as of May 26, 2010, by and among Energy Transfer Equity, L.P., ETE Services Company LLC and Regency Energy Partners LP (incorporated by reference to Exhibit 10.1 of Form 8-K, file No. 1-32740, filed May 1, 2013)
10.43	Second Amendment, dated April 30, 2013, to the Shared Services Agreement dated as of August 26, 2005, as amended May 26, 2010, by and between Energy Transfer Equity, L.P. and Energy Transfer Partners, L.P.(incorporated by reference to Exhibit 10.2 of Form 8-K, file No. 1-32740, filed May 1, 2013)
10.44	Amendment No. 2 to Senior Secured Term Loan Agreement by and among Energy Transfer Equity, L.P., the Restricted Persons party thereto, the Lenders party thereto and Credit Suisse AG, in its capacity as administrative agent for the Lenders dated as of April 25, 2012 (incorporated by reference to Exhibit 10.3 of Form 8-K, file No. 1-32740, filed May 1, 2013)
10.45	Amendment No. 1 to Senior Secured Bridge Term Loan Agreement by and among Energy Transfer Equity, L.P., the Restricted Persons party thereto, the Lenders party thereto and Credit Suisse AG, in its capacity as administrative agent for the Lenders dated as of April 25, 2012 (incorporated by reference to Exhibit 10.4 of Form 8-K, file No. 1-32740, filed May 1, 2013)
10.46	Amendment No. 2 to Amended and Restated Credit Agreement by and among Energy Transfer Equity, L.P., the Restricted Persons party thereto, the Lenders party thereto and Credit Suisse AG, in its capacity as administrative agent for the Lenders dated as of April 29, 2012 (incorporated by reference to Exhibit 10.5 of Form 8-K, file No. 1-32740, filed May 1, 2013)
10.47	Exchange and Redemption Agreement by and among Energy Transfer Partners, L.P., Energy Transfer Equity, L.P. and ETE Common Holdings, LLC dated August 7, 2013 (incorporated by reference to Exhibit 10.1 of Form 8-K, file No. 1-32740, filed August 8, 2013)

Exhibit Number	
10.48	Credit Agreement dated as of December 2, 2013 among Energy Transfer Equity, L.P., Credit Suisse AG, Cayman Islands Branch, as administrative agent, and the other lenders party thereto (incorporated by reference to Exhibit 10.1 of Form 8-K, file No. 1-32740, filed December 2, 2013)
10.49	Senior Secured Term Loan Agreement dated as of December 2, 2013 among Energy Transfer Equity, L.P., Credit Suisse AG, Cayman Islands Branch, as administrative agent, and the other lenders party thereto (incorporated by reference to Exhibit 10.2 of Form 8-K, file No. 1-32740, filed December 2, 2013)
10.50	Second Amended and Restated Pledge and Security Agreement dated December 2, 2013 among Energy Transfer Equity, L.P., the other grantors named therein and U.S. Bank National Association, as collateral agent (incorporated by reference to Exhibit 10.3 of Form 8-K, file No. 1-32740, filed December 2, 2013)
10.51	Class D Unit Agreement (incorporated by reference to Exhibit 10.1 of Form 8-K, file No. 1-32740, filed December 27, 2013)
12.1*	Computation of Ratio of Earnings to Fixed Charges.
21.1*	List of Subsidiaries.
23.1*	Consent of Grant Thornton LLP related to Energy Transfer Equity, L.P.
23.2*	Consent of Grant Thornton LLP related to ETE Common Holdings, LLC
23.3*	Consent to Grant Thornton LLP related to Energy Transfer Partners, L.P.
23.4*	Consent of Grant Thornton LLP related to Energy Transfer Partners GP, L.P.
23.5*	Consent of Grant Thornton LLP related to Regency Energy Partners LP
23.6*	Consent of Grant Thornton LLP related to Regency GP LP
23.7*	Consent of Grant Thornton LLP related to ETE GP Acquirer LLC
23.8*	Consent of Grant Thornton LLP related to RIGS Haynesville Partnership Co.
23.9*	Consent of Grant Thornton LLP related to Lone Star NGL LLC
23.10*	Consent of Ernst & Young LLP related to Sunoco Logistics Partners L.P.
23.11*	Consent of PricewaterhouseCoopers LLP related to Midcontinent Express Pipeline LLC
31.1*	Certification of President (Principal 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 President (Principal 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 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	Audited financial statements of RIGS Haynesville Partnership Co. as of December 31, 2013, 2012 and 2011 for the years then ended (incorporated by reference to Exhibit 99.2 of Regency Energy Partners LP Form 10-K, File No 1-35262, filed February 27, 2013)
99.3	Audited financial statements of Midcontinent Express Pipeline LLC as of December 31, 2013 and 2012 and for the years then ended (incorporated by reference to Exhibit 99.3 of Regency Energy Partners LP Form 10-K, File No. 1-35262, filed February 27, 2013)
99.4	Audited financial statements of Midcontinent Express Pipeline LLC as of December 31, 2012 and 2011 and for the years then ended (incorporated by reference to Exhibit 99.4 of Regency Energy Partners LP Form 10-K, File No. 1-35262, filed February 27, 2013)
99.5	Audited financial statements of Lone Star NGL LLC as of December 31, 2013, 2012 and for the period from March 21, 2011 to December 31, 2011 (incorporated by reference to Exhibit 99.5 of Regency Energy Partners LP Form 10-K, File No. 1-35262, filed February 27, 2013)
99.6	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 (incorporated by reference to Exhibit 99.1 of Form 10-Q, file No. 1-32740, filed August 8, 2011)
101*	Interactive data files pursuant to Rule 405 of Regulation S-T: (i) our Consolidated Balance Sheets as of December 31, 2013 and December 31, 2012; (ii) our Consolidated Statements of Operations for the years ended December 31, 2013, 2012 and 2011; (iii) our Consolidated Statements of Comprehensive Income for years ended December 31, 2013, 2012 and 2011; (iv) our Consolidated Statement of Equity for the years ended December 31, 2013, 2012 and 2011; and (v) our Consolidated Statements of Cash Flows for the years ended December 31, 2013, 2012 and 2011.

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

INDEX TO FINANCIAL STATEMENTS

Energy Transfer Equity, L.P. and Subsidiaries

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Partners
Energy Transfer Equity, L.P.

We have audited the accompanying consolidated balance sheets of Energy Transfer Equity, L.P. (a Delaware limited partnership) and subsidiaries (the “Partnership”) as of December 31, 2013 and 2012, 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, 2013. 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 21 percent of consolidated total assets as of December 31, 2012, and total revenues of 19 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. as of December 31, 2012 and for the period from October 5, 2012 to December 31, 2012, 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 Equity, L.P. and subsidiaries as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 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, 2013, based on criteria established in the 1992 *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 27, 2014 expressed an unqualified opinion thereon.

/s/ GRANT THORNTON LLP

Dallas, Texas
February 27, 2014

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

	December 31, 2013	December 31, 2012
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 590	$ 372
Accounts receivable, net	3,658	3,057
Accounts receivable from related companies	63	71
Inventories	1,807	1,522
Exchanges receivable	67	55
Price risk management assets	39	25
Current assets held for sale	—	184
Other current assets	312	311
Total current assets	6,536	5,597
PROPERTY, PLANT AND EQUIPMENT	33,917	30,388
ACCUMULATED DEPRECIATION	(3,235)	(2,104)
	30,682	28,284
NON-CURRENT ASSETS HELD FOR SALE	—	985
ADVANCES TO AND INVESTMENTS IN UNCONSOLIDATED AFFILIATES	4,014	4,737
NON-CURRENT PRICE RISK MANAGEMENT ASSETS	18	43
GOODWILL	5,894	6,434
INTANGIBLE ASSETS, net	2,264	2,291
OTHER NON-CURRENT ASSETS, net	922	533
Total assets	$ 50,330	$ 48,904

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

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

	December 31,	
	2013	2012
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 3,834	$ 3,107
Accounts payable to related companies	14	15
Exchanges payable	284	156
Price risk management liabilities	53	115
Accrued and other current liabilities	1,678	1,754
Current maturities of long-term debt	637	613
Current liabilities held for sale	—	85
Total current liabilities	6,500	5,845
NON-CURRENT LIABILITIES HELD FOR SALE	—	142
LONG-TERM DEBT, less current maturities	22,562	21,440
DEFERRED INCOME TAXES	3,865	3,566
NON-CURRENT PRICE RISK MANAGEMENT LIABILITIES	73	162
PREFERRED UNITS (Note 7)	—	331
OTHER NON-CURRENT LIABILITIES	1,019	995
COMMITMENTS AND CONTINGENCIES (Note 11)		
PREFERRED UNITS OF SUBSIDIARY (Note 7)	32	73
EQUITY:		
General Partner	(3)	—
Limited Partners:		
Common Unitholders (559,923,300 and 559,911,216 units authorized, issued and outstanding as of December 31, 2013 and 2012, respectively)	1,066	2,125
Class D Units (1,540,000 units authorized, issued and outstanding at December 31, 2013)	6	—
Accumulated other comprehensive income (loss)	9	(12)
Total partners’ capital	1,078	2,113
Noncontrolling interest	15,201	14,237
Total equity	16,279	16,350
Total liabilities and equity	$ 50,330	$ 48,904

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

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

	Years Ended December 31,		
	2013	2012	2011
REVENUES:			
Natural gas sales	$ 3,842	$ 2,705	$ 2,982
NGL sales	3,618	2,253	1,716
Crude sales	15,477	2,872	—
Gathering, transportation and other fees	3,097	2,386	1,819
Refined product sales	18,479	5,299	—
Other	3,822	1,449	1,673
Total revenues	48,335	16,964	8,190
COSTS AND EXPENSES:			
Cost of products sold	42,554	13,088	5,169
Operating expenses	1,642	1,116	945
Depreciation and amortization	1,313	871	586
Selling, general and administrative	586	529	253
Goodwill impairment	689	—	—
Total costs and expenses	46,784	15,604	6,953
OPERATING INCOME	1,551	1,360	1,237
OTHER INCOME (EXPENSE):			
Interest expense, net of interest capitalized	(1,221)	(1,018)	(740)
Bridge loan related fees	—	(62)	—
Equity in earnings of unconsolidated affiliates	236	212	117
Gain on deconsolidation of Propane Business	—	1,057	—
Gain on sale of AmeriGas common units	87	—	—
Losses on extinguishments of debt	(162)	(123)	—
Gains (losses) on interest rate derivatives	53	(19)	(78)
Impairments of investments in affiliates	—	—	(5)
Non-operating environmental remediation	(168)	—	—
Other, net	(1)	30	17
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE	375	1,437	548
Income tax expense from continuing operations	93	54	17
INCOME FROM CONTINUING OPERATIONS	282	1,383	531
Income (loss) from discontinued operations	33	(109)	(3)
NET INCOME	315	1,274	528
LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTEREST	119	970	218
NET INCOME ATTRIBUTABLE TO PARTNERS	196	304	310
GENERAL PARTNER’S INTEREST IN NET INCOME	—	2	1
LIMITED PARTNERS’ INTEREST IN NET INCOME	$ 196	$ 302	$ 309
INCOME FROM CONTINUING OPERATIONS PER LIMITED PARTNER UNIT:			
Basic	$ 0.33	$ 0.59	$ 0.69
Diluted	$ 0.33	$ 0.59	$ 0.69
NET INCOME PER LIMITED PARTNER UNIT:			
Basic	$ 0.35	$ 0.57	$ 0.69
Diluted	$ 0.35	$ 0.57	$ 0.69

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

ENERGY TRANSFER EQUITY, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Dollars in millions)

	Years Ended December 31,		
	2013	2012	2011
Net income	$ 315	$ 1,274	$ 528
Other comprehensive income (loss), net of tax:			
Reclassification to earnings of gains and losses on derivative instruments accounted for as cash flow hedges	(4)	(17)	(19)
Change in value of derivative instruments accounted for as cash flow hedges	(1)	12	7
Change in value of available-for-sale securities	2	—	(1)
Actuarial gain (loss) relating to pension and other postretirement benefits	66	(10)	—
Foreign currency translation adjustment	(1)	—	—
Change in other comprehensive income from equity investments	17	(9)	—
	79	(24)	(13)
Comprehensive income	394	1,250	515
Less: Comprehensive income attributable to noncontrolling interest	181	959	209
Comprehensive income attributable to partners	$ 213	$ 291	$ 306

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

ENERGY TRANSFER EQUITY, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF EQUITY
(Dollars in millions)

	General Partner	Common Unitholders	Class D Units	Accumulated Other Comprehensive Income (Loss)	Non-controlling Interest	Total
Balance, December 31, 2010	$ 1	$ 114	$ —	$ 5	$ 6,127	$ 6,247
Distributions to partners	(2)	(524)	—	—	—	(526)
Distributions to noncontrolling interest	—	—	—	—	(779)	(779)
Subsidiary equity offerings, net of issue costs	—	153	—	—	1,750	1,903
Subsidiary units issued in acquisition	—	—	—	—	3	3
Non-cash compensation expense, net of units tendered by employees for tax withholdings	—	1	—	—	33	34
Other, net	—	(1)	—	—	(8)	(9)
Other comprehensive loss, net of tax	—	—	—	(4)	(9)	(13)
Net income	1	309	—	—	218	528
Balance, December 31, 2011	—	52	—	1	7,335	7,388
Distributions to partners	(2)	(664)	—	—	—	(666)
Distributions to noncontrolling interest	—	—	—	—	(1,017)	(1,017)
Units issued in Southern Union Merger (See Note 3)	—	2,354	—	—	—	2,354
Subsidiary equity offerings, net of issue costs	—	33	—	—	1,070	1,103
Subsidiary units issued in acquisition	—	47	—	—	2,248	2,295
Non-cash compensation expense, net of units tendered by employees for tax withholdings	—	1	—	—	31	32
Capital contributions received from noncontrolling interest	—	—	—	—	42	42
Holdco Transaction (see Note 3)	—	—	—	—	3,580	3,580
Other, net	—	—	—	—	(11)	(11)
Other comprehensive loss, net of tax	—	—	—	(13)	(11)	(24)
Net income	2	302	—	—	970	1,274
Balance, December 31, 2012	—	2,125	—	(12)	14,237	16,350
Distributions to partners	(2)	(731)	—	—	—	(733)
Distributions to noncontrolling interest	—	—	—	—	(1,428)	(1,428)
Subsidiary equity offerings, net of issue costs	—	122	—	—	1,637	1,759
Subsidiary units issued in acquisition	(1)	(506)	—	—	507	—
Non-cash compensation expense, net of units tendered by employees for tax withholdings	—	1	6	—	47	54
Capital contributions received from noncontrolling interest	—	—	—	—	18	18
Other, net	—	—	—	4	(39)	(35)
Conversion of Regency Preferred Units for Regency Common Units	—	—	—	—	41	41
Deemed distribution related to SUGS Transaction	—	(141)	—	—	—	(141)
Other comprehensive income, net of tax	—	—	—	17	62	79
Net income	—	196	—	—	119	315
Balance, December 31, 2013	$ (3)	$ 1,066	$ 6	$ 9	$ 15,201	$ 16,279

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

ENERGY TRANSFER EQUITY, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Dollars in millions)

	Years Ended December 31,		
	2013	2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 315	$ 1,274	$ 528
Reconciliation of net income to net cash provided by operating activities:			
Depreciation and amortization	1,313	871	586
Deferred income taxes	43	51	1
Gain on curtailment of other postretirement benefit plans	—	(15)	—
Amortization included in interest expense	(55)	(13)	20
Bridge loan related fees	—	62	—
Non-cash compensation expense	61	47	42
Gain on deconsolidation of Propane Business	—	(1,057)	—
Gain on sale of AmeriGas common units	(87)	—	—
Goodwill impairment	689	—	—
Losses on extinguishments of debt	162	123	—
Losses on disposal of assets	2	4	1
Equity in earnings of unconsolidated affiliates	(236)	(212)	(117)
Distributions from unconsolidated affiliates	313	208	126
LIFO valuation adjustments	(3)	75	—
Other non-cash	51	211	33
Net change in operating assets and liabilities, net of effects of acquisitions and deconsolidations (see Note 2)	(149)	(551)	158
Net cash provided by operating activities	2,419	1,078	1,378
CASH FLOWS FROM INVESTING ACTIVITIES:			
Cash paid for Southern Union Merger, net of cash received (See Note 3)	—	(2,972)	—
Cash proceeds from contribution and sale of propane operations	—	1,443	—
Cash proceeds from the sale of the MGE and NEG assets (See Note 3)	1,008	—	—
Cash proceeds from the sale of AmeriGas common units	346	—	—
Cash paid for all other acquisitions	(405)	(10)	(1,972)
Proceeds from the sale of other assets	89	251	33
Capital expenditures (excluding allowance for equity funds used during construction)	(3,505)	(3,271)	(1,810)
Contributions in aid of construction costs	52	35	25
Contributions to unconsolidated affiliates	(3)	(37)	(222)
Distributions from unconsolidated affiliates in excess of cumulative earnings	419	189	72
Restricted cash	(348)	5	—
Other	—	171	—
Net cash used in investing activities	(2,347)	(4,196)	(3,874)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from borrowings	12,934	12,870	8,262
Repayments of long-term debt	(11,951)	(8,848)	(6,264)
Subsidiary equity offerings, net of issue costs	1,759	1,103	1,903
Distributions to partners	(733)	(666)	(526)
Distributions to noncontrolling interests	(1,428)	(1,017)	(779)
Debt issuance costs	(87)	(112)	(53)
Capital contributions received from noncontrolling interest	18	42	—
Redemption of Preferred Units	(340)	—	—
Other, net	(26)	(8)	(7)
Net cash provided by financing activities	146	3,364	2,536
INCREASE IN CASH AND CASH EQUIVALENTS	218	246	40
CASH AND CASH EQUIVALENTS, beginning of period	372	126	86
CASH AND CASH EQUIVALENTS, end of period	$ 590	$ 372	$ 126

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

ENERGY TRANSFER EQUITY, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Tabular dollar and unit amounts, except per unit data, are in millions)

1. OPERATIONS AND ORGANIZATION:

Financial Statement Presentation

The consolidated financial statements of Energy Transfer Equity, L.P. (the "Partnership," "we" or "ETE") presented herein for the years ended December 31, 2013, 2012 and 2011, have been prepared in accordance with GAAP and pursuant to the rules and regulations of the SEC. We consolidate all majority-owned subsidiaries and limited partnerships, which we control as the general partner or owner of the general partner. All significant intercompany transactions and accounts are eliminated in consolidation. Management has evaluated subsequent events through the date the financial statements were issued.

As discussed in Note 8, in January 2014, the Partnership completed a two-for-one split of ETE Common Units. All references to unit and per unit amounts in the consolidated financial statements and in these notes to the consolidated financial statements have been adjusted to reflect the effect of the unit split for all periods presented.

On March 26, 2012, we acquired all of the outstanding shares of Southern Union. On October 5, 2012, ETP completed the Sunoco Merger and we and ETP also completed the Holdco Transaction at that time. On April 30, 2013, ETP acquired our 60% interest in Holdco. See Note 3 for more information regarding these transactions.

At December 31, 2013, our equity interests in Regency and ETP consisted of 100% of the respective general partner interest and IDRs, as well as the following:

	ETP	Regency
Units held by wholly-owned subsidiaries:		
Common units	49.6	26.3
ETP Class H units	50.2	—
Units held by less than wholly-owned subsidiaries:		
Common units	—	31.4
Regency Class F units	—	6.3

The consolidated financial statements of ETE presented herein include the results of operations of:

- the Parent Company;
- our controlled subsidiaries, ETP and Regency (see description of their respective operations below under "Business Operations");
- ETP's and Regency's consolidated subsidiaries and our wholly-owned subsidiaries that own the general partner and IDR interests in ETP and Regency.

As a result of the Southern Union Merger in March 2012 and the Holdco Transaction in October 2012, the periods presented herein do not include activities from Southern Union or Sunoco prior to the consummation of the respective mergers and/or transactions.

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

Certain prior period amounts have been reclassified to conform to the 2013 presentation. These reclassifications had no impact on net income or total equity. In October 2012, ETP sold Canyon and the results of continuing operations of Canyon have been reclassified to income (loss) from discontinued operations and the prior year amounts have been adjusted to present Canyon's operations as discontinued operations. Canyon was previously included in ETP's midstream operations. In 2013, Southern Union sold its distribution operations. The results of operations of the distribution operations have been reported as income (loss) from discontinued operations. The assets and liabilities of the disposal group have been reported as assets and liabilities held for sale as of December 31, 2012.

Unless the context requires otherwise, references to “we,” “us,” “our,” the “Partnership” and “ETE” mean Energy Transfer Equity, L.P. and its consolidated subsidiaries, which include ETP, ETP GP, ETP LLC, Regency, Regency GP, Regency LLC, Panhandle (or Southern Union prior to its merger into Panhandle in January 2014), Sunoco, Sunoco Logistics and Holdco. References to the “Parent Company” mean Energy Transfer Equity, L.P. on a stand-alone basis.

Business Operations

The Parent Company’s principal sources of cash flow are derived from its direct and indirect investments in the limited partner and general partner interests in ETP and Regency. The Parent Company’s primary cash requirements are for general and administrative expenses, debt service requirements and distributions to its partners. Parent Company-only assets are not available to satisfy the debts and other obligations of ETE’s subsidiaries. In order to understand the financial condition of the Parent Company on a stand-alone basis, see Note 17 for stand-alone financial information apart from that of the consolidated partnership information included herein.

Our activities are primarily conducted through our operating subsidiaries as follows:

- ETP’s operations are conducted through the following subsidiaries:
    - ETC OLP, a Texas limited partnership primarily engaged in midstream and intrastate transportation and storage natural gas operations. ETC OLP owns and operates, through its wholly and majority-owned subsidiaries, natural gas gathering systems, intrastate natural gas pipeline systems and gas processing plants and is engaged in the business of purchasing, gathering, transporting, processing, and marketing natural gas and NGLs in the states of Texas, Louisiana, New Mexico and West Virginia. ETC OLP’s intrastate transportation and storage operations primarily focus on transporting natural gas in Texas through its Oasis pipeline, ET Fuel System, East Texas pipeline and HPL System. ETC OLP’s midstream operations focus on the gathering, compression, treating, conditioning and processing of natural gas, primarily on or through its Southeast Texas System, Eagle Ford System, North Texas System and Northern Louisiana assets. ETC OLP also owns a 70% interest in Lone Star and also owns a convenience store operator with approximately 300 company-owned and dealer locations.
    - ET Interstate, a Delaware limited liability company with revenues consisting primarily of fees earned from natural gas transportation services and operational gas sales. ET Interstate is the parent company of:
        - Transwestern, a Delaware limited liability company engaged in interstate transportation of natural gas. Transwestern’s revenues consist primarily of fees earned from natural gas transportation services and operational gas sales.
        - ETC FEP, a Delaware limited liability company that directly owns a 50% interest in FEP, which owns 100% of the Fayetteville Express interstate natural gas pipeline.
        - ETC Tiger, a Delaware limited liability company engaged in interstate transportation of natural gas.
        - CrossCountry, a Delaware limited liability company that indirectly owns a 50% interest in Citrus Corp., which owns 100% of the FGT interstate natural gas pipeline.
    - ETC Compression, a Delaware limited liability company engaged in natural gas compression services and related equipment sales.
    - Sunoco Logistics is a publicly traded Delaware limited partnership that owns and operates a logistics business, consisting of refined products and crude oil pipelines, terminalling and storage assets, and refined products and crude oil acquisition and marketing assets.
    - Holdco is a Delaware limited liability company that indirectly owns Panhandle and Sunoco. As discussed in Note 3, ETP acquired ETE’s 60% interest in Holdco on April 30, 2013. Panhandle and Sunoco operations are described as follows:
        - Panhandle owns and operates assets in the regulated and unregulated natural gas industry and is primarily engaged in the transportation and storage of natural gas in the United States. As discussed in Note 3, on April 30, 2013, Southern Union completed its contribution to Regency of all of the issued and outstanding membership interests in Southern Union Gathering Company, LLC, and its subsidiaries, including SUGS. Also, as discussed in Note 3, Southern Union completed its sale of the assets of MGE and NEG in 2013. Additionally, as discussed in Note 3, in January 2014, Panhandle consummated a merger with Southern Union, the indirect parent of Panhandle, and PEPL Holdings, the sole limited partner of Panhandle, pursuant to which each of Southern Union and PEPL Holdings were merged with and into Panhandle, with Panhandle surviving the merger.

  - Sunoco owns and operates retail marketing assets, which sell gasoline and middle distillates at retail and operates convenience stores in 24 states, primarily on the east coast and in the midwest region of the United States.

- Regency is a publicly traded partnership engaged in the gathering and processing, compression, treating and transportation of natural gas and the transportation, fractionation and storage of NGLs. Regency focuses on providing midstream services in some of the most prolific natural gas producing regions in the United States, including the Eagle Ford, Haynesville, Barnett, Fayetteville, Marcellus, Utica, Bone Spring, Avalon and Granite Wash shales. Its assets are located in Texas, Louisiana, Arkansas, Pennsylvania, California, Mississippi, Alabama, New Mexico and the mid-continent region of the United States, which includes Kansas, Colorado and Oklahoma. Regency also holds a 30% interest in Lone Star.

Subsequent to the Holdco Transaction on April 30, 2013, our reportable segments changed and currently reflect the following reportable business segments: Investment in ETP; Investment in Regency; and Corporate and Other.

2. ESTIMATES, SIGNIFICANT ACCOUNTING POLICIES AND BALANCE SHEET DETAIL:

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 natural gas and NGL related operations 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 estimated operating results 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 values and results could differ from those estimates.

Revenue Recognition

Our segments are engaged in multiple revenue-generating activities. To the extent that those activities are similar among our segments, revenue recognition policies are similar. Below is a description of revenue recognition policies for significant revenue-generating activities within our segments.

Investment in ETP

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 or installation. 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.

The results of ETP's intrastate transportation and storage and interstate transportation and storage operations are determined primarily by the amount of capacity customers reserve as well as the actual volume of natural gas that flows through the transportation pipelines. Under transportation contracts, 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. Fuel retained for a fee is typically valued at market prices.

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

In addition, ETP's intrastate transportation and storage operations generate revenues and margin from fees charged for storing customers' working natural gas in ETP's storage facilities. ETP also engages in natural gas storage transactions in which ETP seeks to find and profit from pricing differences that occur over time utilizing the Bammel storage reservoir. ETP purchases physical natural gas and then sells financial contracts at a price sufficient to cover ETP's carrying costs and provide for a gross profit margin. ETP expects 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, ETP 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 ETP operate, competitive factors in the energy industry, and other issues.

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

ETP also utilizes other types of arrangements in ETP's midstream operations, 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 ETP gathers and processes natural gas on behalf of producers, sells the resulting residue gas and NGL volumes at market prices and remits to producers an agreed upon percentage of the proceeds based on an index price, (iii) keep-whole arrangements where ETP gathers natural gas from the producer, processes the natural gas and sells the resulting NGLs to third parties at market prices, (iv) purchasing all or a specified percentage of natural gas and/or NGL delivered from producers and treating or processing ETP's plant facilities, and (v) making other direct purchases of natural gas and/or NGL at specified delivery points to meet operational or marketing objectives. In many cases, ETP provides services under contracts that contain a combination of more than one of the arrangements described above. The terms of ETP's contracts vary based on gas quality conditions, the competitive environment at the time the contracts are signed and customer requirements. ETP's 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.

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 ETP's 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.

ETP conducts marketing activities in which ETP markets the natural gas that flows through ETP's assets, referred to as on-system gas. ETP also attracts other customers by marketing volumes of natural gas that do not move through ETP's assets, referred to as off-system gas. For both on-system and off-system gas, ETP purchases natural gas from natural gas producers and other supply points and sells 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.

Terminalling and storage revenues are recognized at the time the services are provided. Pipeline revenues are recognized upon delivery of the barrels to the location designated by the shipper. Crude oil acquisition and marketing revenues, as well as refined product marketing revenues, are recognized when title to the product is transferred to the customer. Revenues are not recognized for crude oil exchange transactions, which are entered into primarily to acquire crude oil of a desired quality or to reduce transportation costs by taking delivery closer to end markets. Any net differential for exchange transactions is recorded as an adjustment of inventory costs in the purchases component of cost of products sold and operating expenses in the statements of operations.

ETP's retail marketing operations sell gasoline and diesel in addition to a broad mix of merchandise such as groceries, fast foods and beverages at its convenience stores. In addition, some of Sunoco's retail outlets provide a variety of car care services. Revenues related to the sale of products are recognized when title passes, while service revenues are recognized when services are provided. Title passage generally occurs when products are shipped or delivered in accordance with the terms of the respective sales agreements. In addition, revenues are not recognized until sales prices are fixed or determinable and collectability is reasonably assured.

Investment in Regency

Regency earns revenue from (i) domestic sales of natural gas, NGLs and condensate, (ii) natural gas gathering, processing and transportation, (iii) contract compression services and (iv) contract treating services. Revenue associated with sales of natural gas, NGLs and condensate are recognized when title passes to the customer, which is when the risk of ownership passes to the purchaser and physical delivery occurs. Revenue associated with transportation and processing fees are recognized when the service is provided. For contract compression services, revenue is recognized when the service is performed. For gathering and processing services, Regency receives either fees or commodities from natural gas producers depending on the type of contract. Commodities received are in turn sold and recognized as revenue in accordance with the criteria outlined above. Under the percentage-of-proceeds contract type, Regency is paid for its services by keeping a percentage of the NGLs produced and a percentage of the residue gas resulting from processing the natural gas. Under the percentage-of-index contract type, Regency earns revenue by purchasing wellhead natural gas at a percentage of the index price and selling processed natural gas at a price approximating the index price and NGLs to third parties. Regency generally reports revenue gross when it acts as the principal, takes title to the product, and incurs the risks and rewards of ownership. Revenue for fee-based arrangements is presented net, because Regency takes the role of an agent for the producers.

Regulatory Accounting – Regulatory Assets and Liabilities

ETP's interstate transportation and storage operations are subject to regulation by certain state and federal authorities and certain subsidiaries in those operations have accounting policies that conform to the accounting requirements and ratemaking practices of the regulatory authorities. The application of these accounting policies allows certain of ETP's regulated entities 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, ETP ceases to meet the criteria for application of regulatory accounting treatment for these entities, 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.

Southern Union recorded regulatory assets with respect to its distribution operations. At December 31, 2012, there were $123 million of regulatory assets included in our consolidated balance sheet as non-current assets held for sale. Southern Union's distribution operations were sold in 2013.

Although Panhandle's natural gas transmission systems and storage operations are subject to the jurisdiction of FERC in accordance with the NGA and NGPA, it does not currently apply regulatory accounting policies in accounting for its operations. In 1999, prior to its acquisition by Southern Union, Panhandle discontinued the application of regulatory accounting policies primarily due to the level of discounting from tariff rates and its inability to recover specific costs.

Cash, Cash Equivalents and Supplemental Cash Flow Information

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

We place our cash deposits and temporary cash investments with high credit quality financial institutions. At times, our cash and cash equivalents may be uninsured or in deposit accounts that exceed the Federal Deposit Insurance Corporation insurance limit.

The net change in operating assets and liabilities (net of effects of acquisitions, dispositions and deconsolidation) included in cash flows from operating activities was comprised as follows:

	Years Ended December 31,		
	2013	2012	2011
Accounts receivable	$ (556)	$ 267	$ 6
Accounts receivable from related companies	64	(9)	(24)
Inventories	(254)	(258)	51
Exchanges receivable	(8)	14	1
Other current assets	(81)	597	(51)
Other non-current assets, net	(23)	(129)	7
Accounts payable	541	(989)	21
Accounts payable to related companies	(140)	92	6
Exchanges payable	128	—	2
Accrued and other current liabilities	192	(159)	84
Other non-current liabilities	147	26	—
Price risk management assets and liabilities, net	(159)	(3)	55
Net change in operating assets and liabilities, net of effects of acquisitions and deconsolidations	$ (149)	$ (551)	$ 158

Non-cash investing and financing activities and supplemental cash flow information were as follows:

	Years Ended December 31,		
	2013	2012	2011
NON-CASH INVESTING ACTIVITIES:			
Accrued capital expenditures	$ 226	$ 420	$ 226
Net gains (losses) from subsidiary common unit transactions	$ (384)	$ 80	$ 153
AmeriGas limited partner interest received in Propane Contribution (see Note 4)	$ —	$ 1,123	$ —
NON-CASH FINANCING ACTIVITIES:			
Issuance of Common Units in connection with Southern Union Merger (see Note 3)	$ —	$ 2,354	$ —
Long-term debt assumed and non-compete agreement notes payable issued in acquisitions	$ —	$ 6,658	$ 4
Subsidiary issuance of Common Units in connection with certain acquisitions	$ —	$ 2,295	$ 3
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid for interest, net of interest capitalized	$ 1,256	$ 997	$ 728
Cash paid for income taxes	$ 58	$ 23	$ 27

Accounts Receivable

Our subsidiaries assess the credit risk of their customers. Certain of our subsidiaries deal with counterparties that are typically either investment grade or are otherwise secured with a letter of credit or other form of security (corporate guarantee prepayment, master setoff agreement or collateral). Management reviews accounts receivable and an allowance for doubtful accounts is determined based on the overall creditworthiness of customers, historical write-off experience, general and specific economic trends, and specific identification.

Inventories

Inventories consist principally of natural gas held in storage, crude oil, petroleum and chemical products. Natural gas held in storage is valued at the lower of cost or market utilizing the weighted-average cost method. The cost of crude oil and petroleum and chemical products is determined using the last-in, first out method. The cost of appliances, parts and fittings is determined by the first-in, first-out method.

Inventories consisted of the following:

	December 31,	
	2013	2012
Natural gas and NGLs	$ 523	$ 338
Crude oil	488	418
Refined products	597	572
Appliances, parts and fittings and other	199	194
Total inventories	$ 1,807	$ 1,522

ETP utilizes commodity derivatives to manage price volatility associated with its natural gas inventory. Changes in fair value of designated hedged inventory are recorded in inventory on our consolidated balance sheets and in cost of products sold in our consolidated statements of operations.

Exchanges

Exchanges consist of natural gas and NGL delivery imbalances (over and under deliveries) with others. These amounts, which are valued at market prices or weighted average market prices pursuant to contractual imbalance agreements, turn over monthly and are recorded as exchanges receivable or exchanges payable on our consolidated balance sheets. These imbalances are generally settled by deliveries of natural gas or NGLs, but may be settled in cash, depending on contractual terms.

Other Current Assets

Other current assets consisted of the following:

	December 31,	
	2013	2012
Deposits paid to vendors	$ 49	$ 41
Prepaid and other	263	270
Total other current assets	$ 312	$ 311

Property, Plant and Equipment

Property, plant and equipment are stated at cost less accumulated depreciation. Depreciation is computed using the straight-line method over the estimated useful or FERC mandated lives of the assets, if applicable. 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. Natural gas and NGLs used to maintain pipeline minimum pressures is capitalized and classified as property, plant and equipment. Additionally, our subsidiaries 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 our consolidated statements of operations.

We and our subsidiaries review property, plant and equipment for impairment whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. If such a review should indicate that the carrying amount of long-lived assets is not recoverable, we reduce the carrying amount of such assets to fair value. A write down of the carrying amounts of the Canyon assets to their fair values was recorded for approximately $128 million during the year ended December 31, 2012.

Capitalized interest is included for pipeline construction projects, except for certain interstate projects for which an allowance for funds used during construction ("AFUDC") is accrued. Interest is capitalized based on the current borrowing rate when the related costs are incurred. AFUDC is calculated under guidelines prescribed by the FERC and capitalized as part of the cost of utility plant for interstate projects. It represents the cost of servicing the capital invested in construction work-in-process. AFUDC is segregated into two component parts - borrowed funds and equity funds.

Components and useful lives of property, plant and equipment were as follows:

	December 31,	
	2013	2012
Land and improvements	$ 881	$ 553
Buildings and improvements (5 to 45 years)	939	692
Pipelines and equipment (5 to 83 years)	21,494	19,505
Natural gas and NGL storage facilities (5 to 46 years)	1,083	1,057
Bulk storage, equipment and facilities (2 to 83 years)	1,933	1,745
Tanks and other equipment (5 to 40 years)	1,697	1,194
Retail equipment (3 to 99 years)	450	258
Vehicles (1 to 25 years)	156	154
Right of way (20 to 83 years)	2,190	2,134
Furniture and fixtures (2 to 25 years)	51	67
Linepack	118	118
Pad gas	52	58
Other (1 to 48 years)	708	880
Construction work-in-process	2,165	1,973
	33,917	30,388
Less – Accumulated depreciation	(3,235)	(2,104)
Property, plant and equipment, net	$ 30,682	$ 28,284

We recognized the following amounts of depreciation expense and capitalized interest expense for the periods presented:

	Years Ended December 31,		
	2013	2012	2011
Depreciation expense [(1)]	$ 1,128	$ 801	$ 531
Capitalized interest, excluding AFUDC	$ 43	$ 99	$ 13

(1) Depreciation expense amounts have been adjusted by $26 million for the year ended December 31, 2011 to present Canyon's operations as discontinued operations.

Advances to and Investments in Affiliates

Certain of our subsidiaries own interests in a number of related businesses that are accounted for by the equity method. In general, we use the equity method of accounting for an investment for which we exercise significant influence over, but do not control, the investee's operating and financial policies.

Goodwill

Goodwill is tested for impairment annually or more frequently if circumstances indicate that goodwill might be impaired. Our annual impairment test is performed as of August 31 for reporting units within ETP's intrastate transportation and storage and midstream operations and during the fourth quarter for reporting units within ETP's interstate transportation and storage and NGL transportation and services operations and all others, including all of Regency's reporting units.

Changes in the carrying amount of goodwill were as follows:

	Investment in ETP	Investment in Regency	Corporate, Other and Eliminations	Total
Balance, December 31, 2011	$ 1,220	$ 790	$ 29	$ 2,039
Goodwill acquired [1]	5,138	337	(328)	5,147
Goodwill sold in deconsolidation of ETP Propane Business	(619)	—	—	(619)
Goodwill allocated to the disposal group	(133)	—	—	(133)
Balance, December 31, 2012	5,606	1,127	(299)	6,434
Goodwill acquired	156	—	—	156
Deconsolidation of SUGS [1]	(337)	—	337	—
Goodwill impairment	(689)	—	—	(689)
Other	(7)	—	—	(7)
Balance, December 31, 2013	$ 4,729	$ 1,127	$ 38	$ 5,894

(1) As discussed in Note 3, Regency completed its acquisition of SUGS on April 30, 2013 which was a transaction between entities under common control. Therefore, the investment in Regency segment amounts have been retrospectively adjusted to reflect SUGS beginning March 26, 2012. Therefore, the December 31, 2012 goodwill balance includes goodwill attributable to SUGS of $337 million in both segments that was correspondingly included in the elimination column. ETP deconsolidated SUGS on April 30, 2013.

Goodwill is recorded at the acquisition date based on a preliminary purchase price allocation and generally may be adjusted when the purchase price allocation is finalized. We recorded a net increase in goodwill of $4.40 billion during the year ended December 31, 2012 primarily due to the Southern Union and Sunoco Mergers where we recorded goodwill of $2.50 billion and $2.64 billion, respectively. We recorded a net decrease in goodwill of $540 million during the year ended December 31, 2013 primarily due to Trunkline LNG's goodwill impairment of $689 million (see below). These decreases were offset by additional goodwill of $156 million from acquisitions in 2013. The additional goodwill recorded during the years ended December 31, 2012 and 2013 is not expected to be deductible for tax purposes.

During the fourth quarter of 2013, ETP performed a goodwill impairment test on its Trunkline LNG reporting unit. In accordance with GAAP, ETP performed step one of the goodwill impairment test and determined that the estimated fair value of the Trunkline LNG reporting unit was less than its carrying amount, primarily due to changes related to (i) the structure and capitalization of the planned LNG export project at Trunkline LNG's Lake Charles facility, (ii) an analysis of current macroeconomic factors, including global natural gas prices and relative spreads, as of the date of our assessment, (iii) judgments regarding the prospect of obtaining regulatory approval for a proposed LNG export project and the uncertainty associated with the timing of such approvals, and (iv) changes in assumptions related to potential future revenues from the import facility and the proposed export facility. An assessment of these factors in the fourth quarter of 2013 led to a conclusion that the estimated fair value of the Trunkline LNG reporting unit was less than its carrying amount. ETP then applied the second step in the goodwill impairment test, allocating the estimated fair value of the reporting unit among all of the assets and liabilities of the reporting unit in a hypothetical purchase price allocation. The assets and liabilities of the reporting unit had recently been measured at fair value in 2012 as a result of the acquisition of Southern Union, and those estimated fair values had been recorded at the reporting unit through the application of "push-down" accounting. For purposes of the hypothetical purchase price allocation used in the goodwill impairment test, ETP estimated the fair value of the assets and liabilities of the reporting unit in a manner similar to the original purchase price allocation. In allocating value to the property, plant and equipment, ETP used current replacement costs adjusted for assumed depreciation. ETP also included the estimated fair value of working capital and identifiable intangible assets in the reporting unit. ETP adjusted deferred income taxes based on these estimated fair values. Based on this hypothetical purchase price allocation, estimated goodwill was $184 million, which was less than the balance of $873 million that had originally been recorded by the reporting unit through "push-down" accounting in 2012. As a result, ETP recorded a goodwill impairment of $689 million during the fourth quarter of 2013.

No other goodwill impairments were identified or recorded for our reporting units.

Intangible Assets

Intangible assets are stated at cost, net of amortization computed on the straight-line method. We eliminate from our consolidated balance sheets the gross carrying amount and the related accumulated amortization for any fully amortized intangibles in the year they are fully amortized.

Components and useful lives of intangible assets were as follows:

	December 31, 2013		December 31, 2012	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Amortizable intangible assets:				
Customer relationships, contracts and agreements (3 to 46 years)	$ 2,135	$ (264)	$ 2,032	$ (150)
Trade names (20 years)	66	(12)	66	(8)
Patents (9 years)	48	(6)	48	(1)
Other (10 to 15 years)	7	(4)	4	(1)
Total amortizable intangible assets	2,256	(286)	2,150	(160)
Non-amortizable intangible assets:				
Trademarks	294	—	301	—
Total intangible assets	$ 2,550	$ (286)	$ 2,451	$ (160)

Aggregate amortization expense of intangibles assets was as follows:

	Years Ended December 31,		
	2013	2012	2011
Reported in depreciation and amortization	$ 120	$ 70	$ 55

Estimated aggregate amortization expense of intangible assets for the next five years was as follows:

Years Ending December 31:	
2014	$ 123
2015	123
2016	123
2017	123
2018	122

We review amortizable intangible assets for impairment whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. If such a review should indicate that the carrying amount of amortizable intangible assets is not recoverable, we reduce the carrying amount of such assets to fair value. We review non-amortizable intangible assets for impairment annually, or more frequently if circumstances dictate.

Other Non-Current Assets, net

Other non-current assets, net are stated at cost less accumulated amortization. Other non-current assets, net consisted of the following:

	December 31,	
	2013	2012
Unamortized financing costs (3 to 30 years)	$ 167	$ 152
Regulatory assets	86	93
Deferred charges	144	140
Restricted funds	378	—
Other	147	148
Total other non-current assets, net	$ 922	$ 533

Restricted funds primarily consisted of restricted cash held in our wholly-owned captive insurance companies.

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, 2013 and 2012 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.

Below is a schedule of AROs by entity recorded as other non-current liabilities in ETP's consolidated balance sheet:

	December 31,	
	2013	2012
Southern Union	$ 55	$ 46
Sunoco	84	53
Sunoco Logistics	41	41
	$ 180	$ 140

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 has 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, 2013, there were no legally restricted funds for the purpose of settling AROs.

Accrued and Other Current Liabilities

Accrued and other current liabilities consisted of the following:

	December 31,	
	2013	2012
Interest payable	$ 357	$ 334
Customer advances and deposits	142	61
Accrued capital expenditures	260	427
Accrued wages and benefits	173	250
Taxes payable other than income taxes	211	208
Income taxes payable	4	41
Deferred income taxes	119	130
Other	412	303
Total accrued and other current liabilities	$ 1,678	$ 1,754

Deposits or advances are received from customers as prepayments for natural gas deliveries in the following month. Prepayments and security deposits may also be required when customers exceed their credit limits or do not qualify for open credit.

Environmental Remediation

We accrue environmental remediation costs for work at identified sites where an assessment has indicated that cleanup costs are probable and reasonably estimable. Such accruals are undiscounted and are based on currently available information, estimated timing of remedial actions and related inflation assumptions, existing technology and presently enacted laws and regulations. If a range of probable environmental cleanup costs exists for an identified site, the minimum of the range is accrued unless some other point in the range is more likely in which case the most likely amount in the range is accrued.

Fair Value of Financial Instruments

The carrying amounts of cash and cash equivalents, accounts receivable and accounts payable approximate their fair value. Price risk management assets and liabilities are recorded at fair value.

Based on the estimated borrowing rates currently available to us and our subsidiaries for long-term loans with similar terms and average maturities, the aggregate fair value of our consolidated debt obligations as of December 31, 2013 and 2012 was $23.97 billion and $24.15 billion, respectively. As of December 31, 2013 and 2012, the aggregate carrying amount of our consolidated debt obligations was $23.20 billion and $22.05 billion, respectively. The fair value of our consolidated debt obligations is a Level 2 valuation based on the observable inputs used for similar liabilities.

We have commodity derivatives, interest rate derivatives, the Preferred Units, the preferred units of a subsidiary and embedded derivatives in the preferred units of a subsidiary (the “Regency Preferred Units”) 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 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. Derivatives related to the Regency Preferred Units are valued using a binomial lattice model. The market inputs utilized in the model include credit spread, probabilities of the occurrence of certain events, common unit price, dividend yield, and expected value, and are considered Level 3. At December 31, 2012, the fair value of the Preferred Units was based predominantly on an income approach model and considered Level 3. The Preferred Units were redeemed on April 1, 2013.

The following tables summarize the fair value of our financial assets and liabilities measured and recorded at fair value on a recurring basis as of December 31, 2013 and 2012 based on inputs used to derive their fair values:

	Fair Value Measurements at December 31, 2013			
	Fair Value Total	Level 1	Level 2	Level 3
Assets:				
Interest rate derivatives	$ 47	$ —	$ 47	$ —
Commodity derivatives:				
Natural Gas:				
Basis Swaps IFERC/NYMEX	5	5	—	—
Swing Swaps IFERC	8	1	7	—
Fixed Swaps/Futures	203	201	2	—
NGLs — Forwards/Swaps	7	5	2	—
Power — Forwards	3	—	3	—
Refined Products — Futures	5	5	—	—
Total commodity derivatives	231	217	14	—
Total assets	$ 278	$ 217	$ 61	$ —
Liabilities:				
Interest rate derivatives	$ (95)	$ —	$ (95)	$ —
Embedded derivatives in the Regency Preferred Units	(19)	—	—	(19)
Commodity derivatives:				
Condensate — Forward Swaps	(1)	—	(1)	—
Natural Gas:				
Basis Swaps IFERC/NYMEX	(4)	(4)	—	—
Swing Swaps IFERC	(6)	—	(6)	—
Fixed Swaps/Futures	(206)	(201)	(5)	—
Forward Physical Contracts	(1)	—	(1)	—
NGLs — Forwards/Swaps	(9)	(5)	(4)	—
Power — Forwards	(1)	—	(1)	—
Refined Products — Futures	(5)	(5)	—	—
Total commodity derivatives	(233)	(215)	(18)	—
Total liabilities	$ (347)	$ (215)	$ (113)	$ (19)

	Fair Value Measurements at December 31, 2012			
	Fair Value Total	Level 1	Level 2	Level 3
Assets:				
Interest rate derivatives	$ 55	$ —	$ 55	$ —
Commodity derivatives:				
Condensate — Forward Swaps	2	—	2	—
Natural Gas:				
Basis Swaps IFERC/NYMEX	11	11	—	—
Swing Swaps IFERC	3	—	3	—
Fixed Swaps/Futures	98	94	4	—
Options — Calls	3	—	3	—
Options — Puts	1	—	1	—
Forward Physical Contracts	1	—	1	—
NGLs — Swaps	2	1	1	—
Power:				
Forwards	27	—	27	—
Futures	1	1	—	—
Options — Calls	2	—	2	—
Refined Products – Futures	5	1	4	—
Total commodity derivatives	156	108	48	—
Total assets	$ 211	$ 108	$ 103	$ —
Liabilities:				
Interest rate derivatives	$ (235)	$ —	$ (235)	$ —
Preferred Units	(331)	—	—	(331)
Embedded derivatives in the Regency Preferred Units	(25)	—	—	(25)
Commodity derivatives:				
Natural Gas:				
Basis Swaps IFERC/NYMEX	(18)	(18)	—	—
Swing Swaps IFERC	(2)	—	(2)	—
Fixed Swaps/Futures	(103)	(94)	(9)	—
Options — Calls	(3)	—	(3)	—
Options — Puts	(1)	—	(1)	—
NGLs — Swaps	(4)	(3)	(1)	—
Power:				
Forwards	(27)	—	(27)	—
Futures	(2)	(2)	—	—
Refined Products – Futures	(8)	(1)	(7)	—
Total commodity derivatives	(168)	(118)	(50)	—
Total liabilities	$ (759)	$ (118)	$ (285)	$ (356)

At December 31, 2013, the fair value of ETP’s Trunkline LNG reporting unit was classified as Level 3 of the fair value hierarchy due to the significance of unobservable inputs developed using company-specific information. ETP used the income approach to measure the fair value of the Trunkline LNG reporting unit. Under the income approach, ETP calculated the fair value based on the present value of the estimated future cash flows. The discount rate used, which was an unobservable input, was based on the weighted-average cost of capital adjusted for the relevant risk associated with business-specific characteristics and the uncertainty related to the business's ability to execute on the projected cash flows.

The following table presents the material unobservable inputs used to estimate the fair value of Regency's Preferred Units and the embedded derivatives in Regency's Preferred Units:

	Unobservable Input	December 31, 2013
Embedded derivatives in the Regency Preferred Units	Credit Spread	4.16%
	Volatility	23.71%

Changes in the remaining term of the Preferred Units, U.S. Treasury yields and valuations in related instruments would cause a change in the yield to value the Preferred Units. Changes in Regency's cost of equity and U.S. Treasury yields would cause a change in the credit spread used to value the embedded derivatives in the Regency Preferred Units. Changes in Regency's historical unit price volatility would cause a change in the volatility used to value the embedded derivatives.

The following table presents a reconciliation of the beginning and ending balances for our Level 3 financial instruments measured at fair value on a recurring basis using significant unobservable inputs for the year ended December 31, 2013. There were no transfers between the fair value hierarchy levels during the years ended December 31, 2013 or 2012.

Balance, December 31, 2012	$	(356)
Realized loss included in other income (expense)		(9)
Redemption of Preferred Units		340
Net unrealized gains included in other income (expense)		6
Balance, December 31, 2013	$	(19)

Contributions in Aid of Construction Cost

On certain of our capital projects, third parties are obligated to reimburse us for all or a portion of project expenditures. The majority of such arrangements are associated with pipeline construction and production well tie-ins. Contributions in aid of construction costs ("CIAC") are netted against our project costs as they are received, and any CIAC which exceeds our total project costs, is recognized as other income in the period in which it is realized.

Shipping and Handling Costs

Shipping and handling costs related to fuel sold are included in cost of products sold. Shipping and handling costs related to fuel consumed for compression and treating are included in operating expenses and are as follows:

	Years Ended December 31,					
	2013		2012		2011	
Shipping and handling costs – recorded in operating expenses	$	28	$	25	$	40

Costs and Expenses

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

We record the collection of taxes to be remitted to governmental authorities on a net basis except for our retail marketing operations in which consumer excise taxes on sales of refined products and merchandise are included in both revenues and costs and expenses in the consolidated statements of operations, with no effect on net income (loss). Excise taxes collected by ETP's retail marketing operations were $2.22 billion and $573 million for the years ended December 31, 2013 and 2012, respectively.

Issuances of Subsidiary Units

We record changes in our ownership interest of our subsidiaries as equity transactions, with no gain or loss recognized in consolidated net income or comprehensive income. For example, upon ETP's or Regency's issuance of respective ETP or

Regency Common Units in a public offering, we record any difference between the amount of consideration received or paid and the amount by which the noncontrolling interest is adjusted as a change in partners' capital.

Income Taxes

ETE is a publicly traded limited partnership and is not taxable for federal and most state income tax purposes. As a result, our earnings or losses, to the extent not included in a taxable subsidiary, for federal and state income tax purposes are included in the tax returns of the individual partners. Net earnings for financial statement purposes may differ significantly from taxable income reportable to Unitholders as a result of differences between the tax basis and financial reporting basis of assets and liabilities, in addition to the allocation requirements related to taxable income under our Third Amended and Restated Agreement of Limited Partnership (the "Partnership Agreement").

As a publicly traded limited partnership, we are subject to a statutory requirement that our "qualifying income" (as defined by the Internal Revenue Code, related Treasury Regulations, and IRS pronouncements) exceed 90% of our total gross income, determined on a calendar year basis. If our qualifying income does not meet this statutory requirement, we would be taxed as a corporation for federal and state income tax purposes. For the years ended December 31, 2013, 2012 and 2011, our qualifying income met the statutory requirement.

The Partnership conducts certain activities through corporate subsidiaries which are subject to federal, state and local income taxes. Holdco, which owns Sunoco and Southern Union, is a corporate subsidiary. The Partnership and its corporate subsidiaries account for income taxes under the asset and liability method.

Under this method, deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using enacted tax rates in effect for the year in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rate is recognized in earnings in the period that includes the enactment date. Valuation allowances are established when necessary to reduce deferred tax assets to the amounts more likely than not to be realized.

The determination of the provision for income taxes requires significant judgment, use of estimates, and the interpretation and application of complex tax laws. Significant judgment is required in assessing the timing and amounts of deductible and taxable items and the probability of sustaining uncertain tax positions. The benefits of uncertain tax positions are recorded in our financial statements only after determining a more-likely-than-not probability that the uncertain tax positions will withstand challenge, if any, from taxing authorities. When facts and circumstances change, we reassess these probabilities and record any changes through the provision for income taxes.

Accounting for Derivative Instruments and Hedging Activities

For qualifying hedges, we formally document, designate and assess the effectiveness of transactions that receive hedge accounting treatment and the gains and losses offset related results on the hedged item in the statement of operations. 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.

At inception of a hedge, we formally document the relationship between the hedging instrument and the hedged item, the risk management objectives, and the methods used for assessing and testing effectiveness and how any ineffectiveness will be measured and recorded. We also assess, both at the inception of the hedge and on a quarterly basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows. If we determine that a derivative is no longer highly effective as a hedge, we discontinue hedge accounting prospectively by including changes in the fair value of the derivative in net income for the period.

If we designate a commodity 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 the 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.

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

If we designate a derivative financial instrument as a cash flow hedge and it qualifies for hedge accounting, a 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.

We previously have managed a portion of our interest rate exposures by utilizing interest rate swaps and similar instruments. Certain of our interest rate derivatives are accounted for as either cash flow hedges or fair value hedges. For interest rate derivatives accounted for as either cash flow or fair value hedges, we report realized gains and losses and ineffectiveness portions of those hedges in interest expense. For interest rate derivatives not designated as hedges for accounting purposes, we report realized and unrealized gains and losses on those derivatives in gains (losses) on interest rate derivatives in the consolidated statements of operations.

Pensions and Other Postretirement Benefit Plans

Employers are required to recognize in their balance sheets the overfunded or underfunded status of defined benefit pension and other postretirement plans, measured as the difference between the fair value of the plan assets and the benefit obligation (the projected benefit obligation for pension plans and the accumulated postretirement benefit obligation for other postretirement plans). Each overfunded plan is recognized as an asset and each underfunded plan is recognized as a liability. Employers must recognize the change in the funded status of the plan in the year in which the change occurs through AOCI in equity or are reflected as a regulatory asset or regulatory liability for regulated entities.

Allocation of Income

For purposes of maintaining partner capital accounts, our Partnership Agreement specifies that items of income and loss shall generally be allocated among the partners in accordance with their percentage interests.

3. ACQUISITIONS AND RELATED TRANSACTIONS:

2014 Transactions

Panhandle Merger

On January 10, 2014, Panhandle consummated a merger with Southern Union, the indirect parent of Panhandle, and PEPL Holdings, the sole limited partner of Panhandle, pursuant to which each of Southern Union and PEPL Holdings were merged with and into Panhandle (the “Panhandle Merger”), with Panhandle surviving the Panhandle Merger. In connection with the Panhandle Merger, Panhandle assumed Southern Union’s obligations under its 7.6% Senior Notes due 2024, 8.25% Senior Notes due 2029 and the Junior Subordinated Notes due 2066. At the time of the Panhandle Merger, Southern Union did not have operations of its own, other than its ownership of Panhandle and noncontrolling interest in PEI Power II, LLC, Regency (31.4 million Regency Common Units and 6.3 million Regency Class F Units), and ETP (2.2 million ETP Common Units). In connection with the Panhandle Merger, Panhandle also assumed PEPL Holdings’ guarantee of $600 million of Regency senior notes.

Trunkline LNG Transaction

On February 19, 2014, ETE and ETP completed the transfer to ETE of Trunkline LNG, the entity that owns a LNG regasification facility in Lake Charles, Louisiana, from ETP in exchange for the redemption by ETP of 18.7 million ETP Common Units held by ETE. The transaction was effective as of January 1, 2014.

In connection with ETE’s acquisition of Trunkline LNG, ETP agreed to continue to provide management services for ETE through 2015 in relation to both Trunkline LNG’s regasification facility and the development of a liquefaction project at Trunkline LNG’s facility, for which ETE has agreed to pay incremental management fees to ETP of $75 million per year for the years ending December 31, 2014 and 2015. ETE also agreed to provide additional subsidies to ETP through the relinquishment of future incentive distributions, as discussed further in Note 8.

Regency's Pending Acquisition of PVR Partners, L.P.

In October 2013, Regency announced that it entered into a merger agreement with PVR ("PVR Acquisition"), pursuant to which, Regency intends to merge with PVR. This merger will be a unit-for-unit transaction plus a one-time approximately $37 million cash payment to PVR unitholders which represents total consideration of $5.6 billion, including the assumption of net debt of $1.8 billion. The holders of PVR common units, PVR Class B Units and PVR Special Units ("PVR Unit(s)") will receive 1.02 Regency Common Units in exchange for each PVR Unit held on the applicable record date. In November 2013, Regency received clearance of the PVR Acquisition under the Hart-Scott-Rodino Antitrust Improvements Act. The transaction is subject to the approval of PVR's unitholders and other customary closing conditions, and is expected to close in late March 2014. The PVR Acquisition is expected to enhance Regency's geographic diversity with a strategic presence in the Marcellus and Utica shales in the Appalachian Basin and the Granite Wash in the Mid-Continent region.

Regency's Pending Acquisition of Eagle Rock Energy Partners, L.P.'s Midstream Business

On December 23, 2013, Regency announced plans to purchase Eagle Rock Energy Partners, L.P.'s midstream business. This acquisition, valued at approximately $1.3 billion, will complement Regency's core gathering and processing business, and when combined with the proposed acquisition of PVR Resources, will further diversify Regency's basin exposure in the Texas Panhandle, East Texas and South Texas. The Partnership has agreed to purchase approximately 16.5 million Regency Common Units for approximately $400 million upon the closing of this acquisition. The Eagle Rock Acquisition is expected to close in the second quarter of 2014, and is subject to the approval of Eagle Rock's unitholders, Hart-Scott-Rodino Antitrust Improvements Act approval and other customary closing conditions.

Regency's Acquisition of Hoover Energy

On February 3, 2014, Regency completed its previously announced acquisition of the midstream assets of Hoover Energy. The consideration paid by Regency in exchange for the acquired Hoover entities was valued at $282 million (subject to customary post-closing adjustments) and consisted of (i) 4.0 million Regency Common Units issued to Hoover Energy and (ii) $184 million in cash. A portion of the consideration is being held in escrow as security for certain indemnification claims. Regency financed the cash portion of the purchase price through borrowings under its revolving credit facility.

2013 Transactions

Sale of Southern Union's Distribution Operations

In December 2012, Southern Union entered into a purchase and sale agreement with The Laclede Group, Inc., pursuant to which Laclede Missouri agreed to acquire the assets of Southern Union's MGE division and Laclede Massachusetts agreed to acquire the assets of Southern Union NEG division (together, the "LDC Disposal Group"). Laclede Gas Company, a subsidiary of The Laclede Group, Inc., subsequently assumed all of Laclede Missouri's rights and obligations under the purchase and sale agreement. In February 2013, The Laclede Group, Inc. entered into an agreement with Algonquin Power & Utilities Corp ("APUC") that allowed a subsidiary of APUC to assume the rights of The Laclede Group, Inc. to purchase the assets of Southern Union's NEG division.

In September 2013, Southern Union completed its sale of the assets of MGE for an aggregate purchase price of $975 million, subject to customary post-closing adjustments. In December 2013, Southern Union completed its sale of the assets of NEG for cash proceeds of $40 million, subject to customary post-closing adjustments, and the assumption of $20 million of debt.

The LDC Disposal Group's operations have been classified as discontinued operations for all periods in the consolidated statements of operations. The assets and liabilities of the LDC Disposal Group were classified as assets and liabilities held for sale at December 31, 2012.

The following table summarizes selected financial information related to Southern Union's distribution operations in 2013 through MGE and NEG's sale dates in September 2013 and December 2013, respectively, and for the period from March 26, 2012 to December 31, 2012:

	Years Ended December 31,	
	2013	2012
Revenue from discontinued operations	$ 415	$ 324
Net loss of discontinued operations, excluding effect of taxes and overhead allocations	65	43

SUGS Contribution

On April 30, 2013, Southern Union completed its contribution to Regency of all of the issued and outstanding membership interest in Southern Union Gathering Company, LLC, and its subsidiaries, including SUGS (the "SUGS Contribution"). The general partner and IDRs of Regency are owned by ETE. The consideration paid by Regency in connection with this transaction consisted of (i) the issuance of approximately 31.4 million Regency common units to Southern Union, (ii) the issuance of approximately 6.3 million Regency Class F units to Southern Union, (iii) the distribution of $463 million in cash to Southern Union, net of closing adjustments, and (iv) the payment of $30 million in cash to a subsidiary of ETP. This transaction was between commonly controlled entities; therefore, the amounts recorded in the consolidated balance sheet for the investment in Regency and the related deferred tax liabilities were based on the historical book value of SUGS. In addition, PEPL Holdings, a wholly-owned subsidiary of Southern Union, provided a guarantee of collection with respect to the payment of the principal amounts of Regency's debt related to the SUGS Contribution. The Regency Class F units 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.

ETP's Acquisition of ETE's Holdco Interest

On April 30, 2013, ETP acquired ETE's 60% interest in Holdco for approximately 49.5 million of newly issued ETP Common Units and $1.40 billion in cash, less $68 million of closing adjustments (the "Holdco Acquisition"). As a result, ETP now owns 100% of Holdco. ETE, which owns the general partner and IDRs of ETP, agreed to forego incentive distributions on the newly issued ETP units for each of the first eight consecutive quarters beginning with the quarter in which the closing of the transaction occurred and 50% of incentive distributions on the newly issued ETP units for the following eight consecutive quarters. ETP controlled Holdco prior to this acquisition; therefore, the transaction did not constitute a change of control.

2012 Transactions

Southern Union Merger

On March 26, 2012, ETE completed its acquisition of Southern Union. Southern Union was the surviving entity in the merger and operated as a wholly-owned subsidiary of ETE until our contribution to Holdco discussed below.

Under the terms of the merger agreement, Southern Union stockholders received a total of approximately 57 million ETE Common Units and a total of approximately $3.01 billion in cash. Effective with the closing of the transaction, Southern Union's common stock was no longer publicly traded.

Citrus Acquisition

In connection with the Southern Union Merger on March 26, 2012, ETP completed its acquisition of CrossCountry, a subsidiary of Southern Union which owned an indirect 50% interest in Citrus, the owner of FGT. The total merger consideration was approximately $2.0 billion, consisting of approximately $1.9 billion in cash and approximately 2.2 million ETP Common Units. See Note 4 for more information regarding ETP's equity method investment in Citrus.

Sunoco Merger

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 a total of 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 ETP.

Prior to the Sunoco Merger, on September 8, 2012, Sunoco completed the exit from its Northeast refining operations by contributing the refining assets at its Philadelphia refinery and various commercial contracts to PES, a joint venture with The Carlyle Group. Sunoco also permanently idled the main refining processing units at its Marcus Hook refinery in June 2012. The Marcus Hook facility continued to support operations at the Philadelphia refinery prior to commencement of the PES joint venture. Under the terms of the joint venture agreement, The Carlyle Group contributed cash in exchange for a 67% controlling interest in PES. In exchange for contributing its Philadelphia refinery assets and various commercial contracts to the joint venture, Sunoco retained an approximately 33% non-operating noncontrolling interest. The fair value of Sunoco's retained interest in PES, which was $75 million on the date on which the joint venture was formed, was determined based on the equity contributions of The Carlyle Group. Sunoco has indemnified PES for environmental liabilities related to the

Philadelphia refinery that arose from the operation of such assets prior the formation of the joint venture. The Carlyle Group will oversee day-to-day operations of PES and the refinery. JPMorgan Chase will provide working capital financing to PES in the form of an asset-backed loan, supply crude oil and other feedstocks to the refinery at the time of processing and purchase certain blendstocks and all finished refined products as they are processed. Sunoco entered into a supply contract for gasoline and diesel produced at the refinery for its retail marketing business.

ETP incurred merger related costs related to the Sunoco Merger of $28 million during the year ended December 31, 2012. Sunoco's revenue included in our consolidated statement of operations was approximately $5.93 billion during October through December 2012. Sunoco's net loss included in our consolidated statement of operations was approximately $14 million during October through December 2012. Sunoco Logistics' revenue included in our consolidated statement of operations was approximately $3.11 billion during October through December 2012. Sunoco Logistics' net income included in our consolidated statement of operations was approximately $145 million during October through December 2012.

Holdco Transaction

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. 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 90.7 million Class F Units representing limited partner interests in ETP ("ETP Class F Units"). The Class F Units were exchanged for Class G Units in 2013 as discussed in Note 8. Pursuant to a stockholders agreement between ETE and ETP, ETP controlled Holdco (prior to ETP's acquisition of ETE's 60% equity interest in Holdco in 2013) and therefore, ETP consolidated Holdco (including Sunoco and Southern Union) in its financial statements subsequent to consummation of the Holdco Transaction.

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.

Summary of Assets Acquired and Liabilities Assumed

We accounted for the Southern Union Merger and Sunoco Merger using the acquisition method of accounting, which requires, among other things, that assets acquired and liabilities assumed be recognized on the balance sheet at their fair values as of the acquisition date. Our consolidated balance sheet presented as of December 31, 2012 reflects the purchase price allocations. Certain amounts included in the purchase price allocation as of December 31, 2012 for Southern Union have been changed from amounts reflected as of March 31, 2012 based on management's review of the valuation.

The following table summarizes the assets acquired and liabilities assumed as of the respective acquisition dates:

	Sunoco [1]	Southern Union[2]
Current assets	$ 7,312	$ 556
Property, plant and equipment	6,686	6,242
Goodwill	2,641	2,497
Intangible assets	1,361	55
Investments in unconsolidated affiliates	240	2,023
Note receivable	821	—
Other assets	128	163
	19,189	11,536
Current liabilities	4,424	1,348
Long-term debt obligations, less current maturities	2,879	3,120
Deferred income taxes	1,762	1,419
Other non-current liabilities	769	284
Noncontrolling interest	3,580	—
	13,414	6,171
Total consideration	5,775	5,365
Cash received	2,714	37
Total consideration, net of cash received	$ 3,061	$ 5,328

(1) Includes amounts recorded with respect to Sunoco Logistics.

(2) Includes ETP’s acquisition of Citrus.

As a result of the Southern Union Merger, we recognized $38 million of merger-related costs during the year ended December 31, 2012. Southern Union’s revenue included in our consolidated statement of operations was approximately $1.26 billion since the acquisition date to December 31, 2012. Southern Union’s net income included in our consolidated statement of operations was approximately $39 million since the acquisition date to December 31, 2012.

Propane Operations

On January 12, 2012, ETP contributed its propane operations, consisting of HOLP and Titan to AmeriGas. ETP 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, ETP entered into a support agreement with AmeriGas pursuant to which ETP is obligated to provide contingent, residual support of $1.50 billion of intercompany indebtedness owed by AmeriGas to a finance subsidiary that in turn supports the repayment of $1.50 billion of senior notes issued by this AmeriGas finance subsidiary to finance the cash portion of the purchase price.

We have not reflected the Propane Business as discontinued operations as ETP has a continuing involvement in this business as a result of the investment in AmeriGas that was transferred to ETP as consideration for the transaction.

In June 2012, ETP sold the remainder of its retail propane operations, consisting of its cylinder exchange business, to a third party. In connection with the contribution agreement with AmeriGas, certain excess sales proceeds from the sale of the cylinder exchange business were remitted to AmeriGas, and ETP received net proceeds of approximately $43 million.

Sale of Canyon

In October 2012, ETP sold 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. A write down of the carrying amounts of the Canyon assets to their fair values was recorded for approximately $132 million during the year ended December 31, 2012. Canyon was previously included in our Investment in ETP segment.

2011 Transaction

LDH Acquisition

On May 2, 2011, ETP-Regency Midstream Holdings, LLC ("ETP-Regency LLC"), a joint venture owned 70% by ETP and 30% by Regency, acquired all of the membership interest in LDH, from Louis Dreyfus Highbridge Energy LLC for approximately $1.98 billion in cash (the "LDH Acquisition"), including working capital adjustments. ETP contributed approximately $1.38 billion to ETP-Regency LLC to fund its 70% share of the purchase price, while Regency contributed approximately $593 million to fund its 30% share of the purchase price. Subsequent to closing, ETP-Regency LLC was renamed Lone Star.

Lone Star owns and operates a natural gas liquids storage, fractionation and transportation business. Lone Star's storage assets are primarily located in Mont Belvieu, Texas and its West Texas Pipeline transports NGLs through an intrastate pipeline system that originates in the Permian Basin in West Texas, passes through the Barnett Shale production area in North Texas and terminates at the Mont Belvieu storage and fractionation complex. Lone Star also owns and operates fractionation and processing assets located in Louisiana. The acquisition of LDH by Lone Star expanded ETP and Regency's asset portfolios by adding a NGL platform with storage, transportation and fractionation capabilities.

ETP accounted for the LDH Acquisition using the acquisition method of accounting. Lone Star's results of operations are consolidated into ETP's NGL transportation and services operations, while Lone Star's results are recorded as an equity method investment in our Investment in Regency segment. Regency's equity method investment in Lone Star is reflected by ETP as noncontrolling interest attributable to Lone Star. These amounts have been eliminated in our consolidated financial statements.

Pro Forma Results of Operations

The following unaudited pro forma consolidated results of operations for the years ended December 31, 2012 and 2011 are presented as if the Sunoco Merger, Holdco Transaction and LDH Acquisition had been completed on January 1, 2011.

	Years Ended December 31,	
	2012	2011
Revenues	$ 40,398	$ 37,560
Net income	868	865
Net income attributable to partners	866	863
Basic net income per Limited Partner unit	$ 1.55	$ 1.54
Diluted net income per Limited Partner unit	$ 1.55	$ 1.54

The pro forma consolidated results of operations include adjustments to:

- include the results of Lone Star beginning January 1, 2010 and Southern Union and Sunoco beginning January 1, 2011;
- include the incremental expenses associated with the fair value adjustments recorded as a result of applying the acquisition method of accounting; and
- include incremental interest expense related to the financing of ETP's proportionate share of the purchase price.

The pro forma information is not necessarily indicative of the results of operations that would have occurred had the transactions been made at the beginning of the periods presented or the future results of the combined operations.

4. ADVANCES TO AND INVESTMENTS IN UNCONSOLIDATED AFFILIATES:

AmeriGas Partners, L.P.

As discussed in Note 3, on January 12, 2012, ETP received approximately 29.6 million AmeriGas common units in connection with the contribution of its propane operations. On July 12, 2013, ETP sold 7.5 million AmeriGas common units for net proceeds of $346 million, and as of December 31, 2013, ETP owned 22.1 million AmeriGas common units representing an approximate 24% limited partner interest.

The carrying amount of ETP's investment in AmeriGas was $746 million and $1.02 billion as of December 31, 2013 and 2012, respectively, and was reflected in ETP's all other operations. As of December 31, 2013, ETP's investment in AmeriGas reflected $439 million in excess of its proportionate share of AmeriGas' limited partners' capital. Of this excess fair value, $184 million is being amortized over a weighted average period of 14 years, and $255 million is being treated as equity method goodwill and non-amortizable intangible assets.

In January 2014, ETP sold 9.2 million AmeriGas common units for net proceeds of $381 million. Net proceeds from this sale were used to repay borrowings under the ETP Credit Facility and general partnership purposes.

Citrus Corp.

On March 26, 2012, ETE consummated the acquisition of Southern Union and, concurrently with the closing of the Southern Union acquisition, CrossCountry, a subsidiary of Southern Union that indirectly owned a 50% interest in Citrus, merged with a subsidiary of ETP and, in connection therewith, ETP paid approximately $1.9 billion in cash and issued $105 million of ETP Common Units (the "Citrus Acquisition") to a subsidiary of ETE. As a result of the consummation of the Citrus Acquisition, ETP owns CrossCountry, which in turn owns a 50% interest in Citrus. The other 50% interest in Citrus is owned by a subsidiary of Kinder Morgan, Inc. Citrus owns 100% of FGT, a natural gas pipeline system that originates in Texas and delivers natural gas to the Florida peninsula.

ETP recorded its investment in Citrus at $2.0 billion, which exceeded its proportionate share of Citrus' equity by $1.03 billion, all of which is treated as equity method goodwill due to the application of regulatory accounting. The carrying amount of ETP's investment in Citrus was $1.89 billion and $1.98 billion at December 31, 2013 and 2012, respectively, and was reflected in ETP's interstate transportation and storage operations.

FEP

ETP has a 50% interest in FEP, a 50/50 joint venture with Kinder Morgan Energy Partners LP. FEP owns the Fayetteville Express pipeline, an approximately 185-mile natural gas pipeline that originates in Conway County, Arkansas, continues eastward through White County, Arkansas and terminates at an interconnect with Trunkline Gas Company in Panola County, Mississippi. The carrying amount of ETP's investment in FEP was $144 million and $159 million as of December 31, 2013 and 2012, respectively, and was reflected in ETP's interstate transportation and storage operations.

Midcontinent Express Pipeline LLC

Regency owns a 50% interest in MEP, which owns approximately 500 miles of natural gas pipelines that extend from Southeast Oklahoma, across Northeast Texas, Northern Louisiana and Central Mississippi to an interconnect with the Transcontinental natural gas pipeline system in Butler, Alabama. The carrying amount of Regency's investment in MEP was $548 million and $581 million as of December 31, 2013 and 2012, respectively, and was reflected in Regency's natural gas transportation operations.

RIGS Haynesville Partnership Co.

Regency owns a 49.99% interest in HPC, which, through its ownership of RIGS, delivers natural gas from Northwest Louisiana to downstream pipelines and markets through a 450-mile intrastate pipeline system. The carrying amount of Regency's investment in HPC was $442 million and $650 million as of December 31, 2013 and 2012, respectively, and was reflected in Regency's natural gas transportation operations.

Summarized Financial Information

The following tables present aggregated selected balance sheet and income statement data for our unconsolidated affiliates, including AmeriGas, Citrus, FEP, HPC and MEP (on a 100% basis for all periods presented).

	December 31, 2013	December 31, 2012
Current assets	$ 1,028	$ 945
Property, plant and equipment, net	10,778	10,979
Other assets	2,664	2,677
Total assets	$ 14,470	$ 14,601
Current liabilities	$ 1,039	$ 1,662
Non-current liabilities	8,139	7,024
Equity	5,292	5,915
Total liabilities and equity	$ 14,470	$ 14,601

	Years Ended December 31, 2013	2012	2011
Revenue	$ 4,695	$ 4,492	$ 3,784
Operating income	1,197	863	928
Net income	699	491	536

In addition to the equity method investments described above our subsidiaries have other equity method investments which are not significant to our consolidated financial statements.

5. NET INCOME PER LIMITED PARTNER UNIT:

Basic net income per limited partner unit is computed by dividing net income, after considering the General Partner's interest, by the weighted average number of limited partner interests outstanding. Diluted net income per limited partner unit is computed by dividing net income (as adjusted as discussed herein), after considering the General Partner's interest, by the weighted average number of limited partner interests outstanding and the assumed conversion of our Preferred Units, see Note 7. For the diluted earnings per share computation, income allocable to the limited partners is reduced, where applicable, for the decrease in earnings from ETE's limited partner unit ownership in ETP or Regency that would have resulted assuming the incremental units related to ETP's or Regency's equity incentive plans, as applicable, had been issued during the respective periods. Such units have been determined based on the treasury stock method.

The calculation below for the years ended December 31, 2012 and 2011 for diluted net income per limited partner unit excludes the impact of any ETE Common Units that would be issued upon conversion of the Preferred Units, because inclusion would have been antidilutive. The Preferred Units were redeemed April 1, 2013 as discussed in Note 7.

A reconciliation of net income and weighted average units used in computing basic and diluted net income per unit is as follows:

	Years Ended December 31,		
	2013	2012	2011
Income from continuing operations	$ 282	$ 1,383	$ 531
Less: Income from continuing operations attributable to noncontrolling interest	99	1,070	221
Income from continuing operations, net of noncontrolling interest	183	313	310
Less: General Partner's interest in income from continuing operations	—	1	1
Income from continuing operations available to Limited Partners	$ 183	$ 312	$ 309
Basic Income from Continuing Operations per Limited Partner Unit:			
Weighted average limited partner units	560.9	533.4	445.9
Basic income from continuing operations per Limited Partner unit	$ 0.33	$ 0.59	$ 0.69
Basic income (loss) from discontinued operations per Limited Partner unit	$ 0.02	$ (0.02)	$ —
Diluted Income from Continuing Operations per Limited Partner Unit:			
Income from continuing operations available to Limited Partners	$ 183	$ 312	$ 309
Dilutive effect of equity-based compensation of subsidiaries	—	(1)	(1)
Diluted income from continuing operations available to Limited Partners	183	311	308
Weighted average limited partner units	560.9	533.4	445.9
Dilutive effect of unconverted unit awards	—	—	—
Weighted average limited partner units, assuming dilutive effect of unvested unit awards	560.9	533.4	445.9
Diluted income from continuing operations per Limited Partner unit	$ 0.33	$ 0.59	$ 0.69
Diluted income (loss) from discontinued operations per Limited Partner unit	$ 0.02	$ (0.02)	$ —

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6. DEBT OBLIGATIONS:

Our debt obligations consist of the following:

	December 31, 2013	December 31, 2012
Parent Company Indebtedness:		
7.50% Senior Notes, due October 15, 2020	$ 1,187	$ 1,800
5.875% Senior Notes, due January 15, 2024	450	—
ETE Senior Secured Term Loan, due March 26, 2017	—	2,000
ETE Senior Secured Term Loan, due December 2, 2018	171	—
ETE Senior Secured Term Loan, due December 2, 2019	1,000	—
ETE Senior Secured Revolving Credit Facility	—	60
Unamortized premiums, discounts and fair value adjustments, net	(7)	(34)
	2,801	3,826
Subsidiary Indebtedness:		
ETP Debt		
6.0% Senior Notes due July 1, 2013	—	350
8.5% Senior Notes due April 15, 2014	292	292
5.95% Senior Notes due February 1, 2015	750	750
6.125% Senior Notes due February 15, 2017	400	400
6.7% Senior Notes due July 1, 2018	600	600
9.7% Senior Notes due March 15, 2019	400	400
9.0% Senior Notes due April 15, 2019	450	450
4.15% Senior Notes due October 1, 2020	700	—
4.65% Senior Notes due June 1, 2021	800	800
5.20% Senior Notes due February 1, 2022	1,000	1,000
3.60% Senior Notes due February 1, 2023	800	—
4.9% Senior Notes due February 1, 2024	350	—
7.6% Senior Notes due February 1, 2024	277	—
8.25% Senior Notes due November 15, 2029	267	—
6.625% Senior Notes due October 15, 2036	400	400
7.5% Senior Notes due July 1, 2038	550	550
6.05% Senior Notes due June 1, 2041	700	700
6.5% Senior Notes due February 1, 2042	1,000	1,000
5.15% Senior Notes due February 1, 2043	450	—
5.95% Senior Notes due October 1, 2043	450	—
Floating Rate Junior Subordinated Notes due November 1, 2066	546	—
ETP $2.5 billion Revolving Credit Facility due October 27, 2017	65	1,395
Unamortized premiums, discounts and fair value adjustments, net	(34)	(14)
	11,213	9,073
Panhandle Debt		
6.05% Senior Notes due August 15, 2013	—	250
6.20% Senior Notes due November 1, 2017	300	300
7.00% Senior Notes due June 15, 2018	400	400
8.125% Senior Notes due June 1, 2019	150	150
7.00% Senior Notes due July 15, 2029	66	66
Term Loan due February 23, 2015	—	455
Unamortized premiums, discounts and fair value adjustments, net	107	136
	1,023	1,757
Regency Debt		
9.375% Senior Notes due June 1, 2016	—	162
6.875% Senior Notes due December 1, 2018	600	600
5.75% Senior Notes due September 1, 2020	400	—
6.5% Senior Notes due July 15, 2021	500	500
5.5% Senior Notes due April 15, 2023	700	700
4.5% Senior Notes due November 1, 2023	600	—
Regency $1.2 billion Revolving Credit Facility due May 21, 2018	510	192
Unamortized premiums, discounts and fair value adjustments, net	—	3
	3,310	2,157

Southern Union Debt[1]		
7.60% Senior Notes due February 1, 2024	82	360
8.25% Senior Notes due November 14, 2029	33	300
Floating Rate Junior Subordinated Notes due November 1, 2066	54	600

Southern Union $700 million Revolving Credit Facility due May 20, 2016	—	210
Unamortized premiums, discounts and fair value adjustments, net	48	49
	217	1,519
Sunoco Debt		
4.875% Senior Notes due October 15, 2014	250	250
9.625% Senior Notes due April 15, 2015	250	250
5.75% Senior Notes due January 15, 2017	400	400
9.00% Debentures due November 1, 2024	65	65
Unamortized premiums, discounts and fair value adjustments, net	70	104
	1,035	1,069
Sunoco Logistics Debt		
8.75% Senior Notes due February 15, 2014(2)	175	175
6.125% Senior Notes due May 15, 2016	175	175
5.50% Senior Notes due February 15, 2020	250	250
4.65% Senior Notes due February 15, 2022	300	300
3.45% Senior Notes due January 15, 2023	350	—
6.85% Senior Notes due February 15, 2040	250	250
6.10% Senior Notes due February 15, 2042	300	300
4.95% Senior Notes due January 15, 2043	350	—
Sunoco Logistics $200 million Revolving Credit Facility due August 21, 2014	—	26
Sunoco Logistics $35 million Revolving Credit Facility due April 30, 2015	35	20
Sunoco Logistics $350 million Revolving Credit Facility due August 22, 2016	—	93
Sunoco Logistics $1.50 billion Revolving Credit Facility due November 1, 2018	200	—
Unamortized premiums, discounts and fair value adjustments, net	118	143
	2,503	1,732
Transwestern Debt		
5.39% Senior Notes due November 17, 2014	88	88
5.54% Senior Notes due November 17, 2016	125	125
5.64% Senior Notes due May 24, 2017	82	82
5.36% Senior Notes due December 9, 2020	175	175
5.89% Senior Notes due May 24, 2022	150	150
5.66% Senior Notes due December 9, 2024	175	175
6.16% Senior Notes due May 24, 2037	75	75
Unamortized premiums, discounts and fair value adjustments, net	(1)	(1)
	869	869
Other	228	51
	23,199	22,053
Less: current maturities	637	613
	$ 22,562	$ 21,440

(1) In connection with the Panhandle Merger, Southern Union's debt obligations were assumed by Panhandle.

(2) Sunoco Logistics' 8.75% Senior Notes due February 15, 2014 were classified as long-term debt as Sunoco Logistics repaid these notes in February 2014 with borrowings under its $1.50 billion credit facility due November 2018.

The following table reflects future maturities of long-term debt for each of the next five years and thereafter. These amounts exclude $301 million in unamortized premiums and fair value adjustments, net:

2014	$ 812
2015	1,047
2016	375
2017	1,220
2018	1,976
Thereafter	17,468
Total	$ 22,898

Long-term debt reflected on our consolidated balance sheets includes fair value adjustments related to interest rate swaps, which represent fair value adjustments that had been recorded in connection with fair value hedge accounting prior to the termination of the interest rate swap.

Notes and Debentures

ETE Senior Notes

On December 2, 2013, the Parent Company completed a public offering of $450 million aggregate principal amount of its 5.875% Senior Notes due 2024. The Parent Company used net proceeds from this offering, together with a portion of the net proceeds from the Revolver Credit Agreement and the ETE Term Loan Facility, discussed below, to fund the Parent Company's tender offer for a portion of its 7.500% Senior Notes due 2020 (together with the 5.875% Senior Notes due 2024, the "ETE Senior Notes").

The ETE Senior Notes are the Parent Company's senior obligations, ranking equally in right of payment with our other existing and future unsubordinated debt and senior to any of its future subordinated debt. The Parent Company's obligations under the ETE Senior Notes are secured on a first-priority basis with its obligations under the Revolver Credit Agreement and the ETE Term Loan Facility, by a lien on substantially all of the Parent Company's and certain of its subsidiaries' tangible and intangible assets, subject to certain exceptions and permitted liens. The ETE Senior Notes are not guaranteed by any of the Parent Company's subsidiaries.

The covenants related to the ETE Senior Notes include a limitation on liens, a limitation on transactions with affiliates, a restriction on sale-leaseback transactions and limitations on mergers and sales of all or substantially all of the Parent Company's assets.

ETP as Co-Obligor of Sunoco Debt

In connection with the Sunoco Merger and Holdco Transaction, ETP became a co-obligor on approximately of $965 million aggregate principal amount of Sunoco's existing senior notes and debentures.

Southern Union Junior Subordinated Notes

The interest rate on the remaining portion of Southern Union's $600 million Junior Subordinated Notes due 2066 is a variable rate based upon the three-month LIBOR rate plus 3.0175%. The balance of the variable rate portion of the Junior Subordinated Notes was $600 million at an effective interest rate of 3.32% at December 31, 2013.

ETP Senior Notes

The ETP Senior Notes are unsecured obligations of ETP and the obligation of ETP to repay the ETP Senior Notes is not guaranteed by us or any of ETP's subsidiaries. The ETP Senior Notes effectively rank junior to all indebtedness and other liabilities of ETP's existing and future subsidiaries. The balance is payable upon maturity. Interest on the ETP Senior Notes is paid semi-annually.

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 its 5.15% Senior Notes due February 1, 2043. ETP used the net proceeds of $1.24 billion from this offering to repay borrowings outstanding under its revolving credit facility and for general partnership purposes.

In September 2013, ETP issued $700 million aggregate principal amount of 4.15% Senior Notes due October 2020, $350 million aggregate principal amount of 4.90% Senior Notes due February 2024 and $450 million aggregate principal amount of 5.95% Senior Notes due October 2043. ETP used the net proceeds of $1.47 billion from the offering to repay $455 million in borrowings outstanding under the term loan of Panhandle's wholly-owned subsidiary, Trunkline LNG Holdings, LLC, to repay borrowings outstanding under the ETP Credit Facility and for general partnership purposes.

Note Exchange

On June 24, 2013, ETP completed the exchange of approximately $1.09 billion aggregate principal amount of Southern Union's outstanding senior notes, comprising 77% of the principal amount of the 7.6% Senior Notes due 2024, 89% of the principal amount of the 8.25% Senior Notes due 2029 and 91% of the principal amount of the Junior Subordinated Notes due 2066. These notes were exchanged for new notes issued by ETP with the same coupon rates and maturity dates. In conjunction with this transaction, Southern Union entered into intercompany notes payable to ETP, which provide for the reimbursement by Southern Union of ETP's payments under the newly issued notes.

Sunoco Logistics Senior Notes

In January 2013, Sunoco Logistics issued $350 million aggregate principal amount of 3.45% Senior Notes due January 2023 and $350 million aggregate principal amount of 4.95% Senior Notes due January 2043. The net proceeds of $691 million from the offering were used to pay outstanding borrowings under the Sunoco Logistics' Credit Facilities and for general partnership purposes.

Transwestern Senior Notes

The Transwestern notes are payable at any time in whole or pro rata in part, subject to a premium or upon a change of control event or an event of default, as defined. The balance is payable upon maturity. Interest is payable semi-annually.

Regency Senior Notes

The Regency Senior Notes are unsecured obligations of Regency and the obligation of Regency to repay the Regency Senior Notes is not guaranteed by us or any of Regency's subsidiaries. The Regency Senior Notes effectively rank junior to all indebtedness and other liabilities of Regency's existing and future subsidiaries. Interest is payable semi-annually.

Term Loans and Credit Facilities

ETE Term Loan Facility

On December 2, 2013, the Parent Company entered into a Senior Secured Term Loan Agreement (the "ETE Term Credit Agreement"), which has a scheduled maturity date of December 2, 2019, with an option to extend the term subject to the terms and conditions set forth therein. Pursuant to the ETE Term Credit Agreement, the lenders have provided senior secured financing in an aggregate principal amount of $1.0 billion (the "ETE Term Loan Facility"). The Parent Company shall not be required to make any amortization payments with respect to the term loans under the Term Credit Agreement. Under certain circumstances, the Partnership is required to repay the term loan in connection with dispositions of (a) incentive distribution rights in ETP or Regency, (b) general partnership interests in Regency or (c) equity interests of any Person which owns, directly or indirectly, incentive distribution rights in ETP or Regency or general partnership interests in Regency, in each case, yielding net proceeds in excess of $50 million.

Under the Term Credit Agreement, the obligations of the Parent Company are secured by a lien on substantially all of the Parent Company's and certain of its subsidiaries' tangible and intangible assets, subject to certain exceptions and permitted liens. The ETE Term Loan Facility initially is not guaranteed by any of the Parent Company's subsidiaries.

Interest accrues on advances at a LIBOR rate or a base rate plus an applicable margin based on the election of the Parent Company for each interest period. The applicable margin for LIBOR rate loans is 2.50% and the applicable margin for base rate loans is 1.50%. Proceeds of the borrowings under the Term Credit Agreement were used to partially fund a tender offer for ETE Senior Notes completed in December 2013, to repay amounts outstanding under the Parent Company's existing term loan credit facility, and to pay transaction fees and expenses related to the tender offer, the ETE Term Loan Facility and other transactions incidental thereto.

ETE Revolving Credit Facility

On December 2, 2013, the Parent Company entered into a credit agreement (the "Revolving Credit Agreement"), which has a scheduled maturity date of December 2, 2018, with an option for the Partnership to extend the term subject to the terms and conditions set forth therein.

Pursuant to the Revolver Credit Agreement, the lenders have committed to provide advances up to an aggregate principal amount of $600 million at any one time outstanding (the "ETE Revolving Credit Facility"), and the Parent Company has the option to request increases in the aggregate commitments provided that the aggregate commitments never exceed $1.0 billion. In February 2014, the Partnership increased the capacity on the ETE Revolving Credit Facility to $800 million and expects to utilize the additional capacity to fund the purchase of $400 million of Regency common units in connection with Regency's pending Eagle Rock acquisition.

As part of the aggregate commitments under the facility, the Revolver Credit Agreement provides for letters of credit to be issued at the request of the Parent Company in an aggregate amount not to exceed a $150 million sublimit.

Under the Revolver Credit Agreement, the obligations of the Parent Company are secured by a lien on substantially all of the Parent Company's and certain of its subsidiaries' tangible and intangible assets. Borrowings under the Revolver Credit Agreement are not guaranteed by any of the Parent Company's subsidiaries.

Interest accrues on advances at a LIBOR rate or a base rate plus an applicable margin based on the election of the Parent Company for each interest period. The issuing fees for all letters of credit are also based on an applicable margin. The applicable margin used in connection with interest rates and fees is based on the then applicable leverage ratio of the Parent Company. The applicable margin for LIBOR rate loans and letter of credit fees ranges from 1.75% to 2.50% and the applicable margin for base rate loans ranges from 0.75% to 1.50%. The Parent Company will also pay a fee based on its leverage ratio on the actual daily unused amount of the aggregate commitments.

ETP Credit Facility

The ETP Credit Facility allows for borrowings of up to $2.5 billion and expires in October 2017. The indebtedness under the ETP Credit Facility is unsecured and not guaranteed by any of ETP’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 ETP’s other current and future unsecured debt. ETP uses the ETP Credit Facility to provide temporary financing for the Partnership’s growth projects, as well as for general partnership purposes.

In November 2013, ETP amended the ETP Credit Facility to, among other things, (i) extend the maturity date for one additional year to October 2017, (ii) remove the restriction prohibiting unrestricted subsidiaries from owning debt or equity interests in ETP or any restricted subsidiaries of ETP, (iii) amend the covenant limiting fundamental changes to remove the restrictions on mergers or other consolidations of restricted subsidiaries of ETP and to permit ETP to merge with another person and not be the surviving entity provided certain requirements are met, and (iv) amend certain other provisions more specifically set forth in the amendment.

As of December 31, 2013, the ETP Credit Facility had $65 million outstanding, and the amount available for future borrowings was $2.34 billion after taking into account letters of credit of $93 million. The weighted average interest rate on the total amount outstanding as of December 31, 2013 was 1.67%.

Regency Credit Facility

In May 2013, Regency entered into an amendment to the Regency Credit Facility to increase the borrowing capacity of the Regency Credit Facility to $1.20 billion with a $300 million uncommitted incremental facility and extended the maturity date to May 21, 2018. Indebtedness under the Regency Credit Facility is secured by all of Regency’s and certain of its subsidiaries’ tangible and intangible assets and guaranteed by certain of Regency’s subsidiaries.

In February 2014, Regency entered into the First Amendment to Sixth Amended and Restated Credit Agreement to, among other things, expressly permit the pending PVR and Eagle Rock acquisitions, and to increase the commitment to $1.5 billion and increase the uncommitted incremental facility to $500 million.

As of December 31, 2013, Regency had a balance of $510 million outstanding under the Regency Credit Facility in revolving credit loans and approximately $14 million in letters of credit. The total amount available under the Regency Credit Facility, as of December 31, 2013, which is reduced by any letters of credit, was approximately $676 million. The weighted average interest rate on the total amount outstanding as of December 31, 2013 was 2.17%.

The outstanding balance of revolving loans under the Regency Credit Facility bears interest at LIBOR plus a margin or an alternate base rate. The alternate base rate used to calculate interest on base rate loans will be calculated using the greater of a base rate, a federal funds effective rate plus 0.50% and an adjusted one-month LIBOR rate plus 1.0%. The applicable margin ranges from 0.63% to 1.5% for base rate loans and 1.63% to 2.5% for Eurodollar loans.

Regency pays (i) a commitment fee ranging between 0.3% and 0.45% per annum for the unused portion of the revolving loan commitments; (ii) a participation fee for each revolving lender participating in letters of credit ranging between 1.63% and 2.5% per annum of the average daily amount of such lender’s letter of credit exposure and; (iii) a fronting fee to the issuing bank of letters of credit equal to 0.2% per annum of the average daily amount of its letter of credit exposure. In December 2011, Regency amended its credit facility to allow for additional investments in its joint ventures.

Panhandle Term Loans

A portion of the proceeds from ETP’s September 2013 Senior Notes offering, as discussed below, were used to repay $455 million of borrowings under the LNG Holdings’ term loan due February 2015.

Bridge Term Loan Facility

Upon obtaining permanent financing for the Southern Union Merger in March 2012, we terminated a 364-day Bridge Term Loan Facility. For the year ended December 31, 2012, bridge loan related fees reflects the recognition of $62 million of commitment fees upon termination of the facility.

Southern Union Credit Facility

Proceeds from the SUGS Contribution were used to repay borrowings under the Southern Union Credit Facility and the facility was terminated.

Sunoco Logistics Credit Facilities

In November 2013, Sunoco Logistics replaced its existing $350 million and $200 million unsecured credit facilities with a new $1.50 billion unsecured credit facility (the "$1.50 billion Credit Facility"). The $1.50 billion Credit Facility contains an accordion feature, under which the total aggregate commitment may be extended to $2.25 billion under certain conditions. Outstanding borrowings under the $350 million and $200 million credit facilities of $119 million at December 31, 2012 were repaid during the first quarter of 2013.

The $1.50 billion Credit Facility, which matures in November 2018, is available to fund Sunoco Logistics' working capital requirements, to finance acquisitions and capital projects, to pay distributions and for general partnership purposes. The $1.50 billion Credit Facility bears interest at LIBOR or the Base Rate, each plus an applicable margin. The credit facility may be prepaid at any time. Outstanding borrowings under this credit facility were $200 million at December 31, 2013.

West Texas Gulf Pipe Line Company, a subsidiary of Sunoco Logistics, has a $35 million revolving 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 $35 million at December 31, 2013.

Covenants Related to Our Credit Agreements

Covenants Related to the Parent Company

The ETE Term Loan Facility and ETE Revolving Credit Facility contain customary representations, warranties, covenants and events of default, including a change of control event of default and limitations on incurrence of liens, new lines of business, merger, transactions with affiliates and restrictive agreements.

The ETE Term Loan Facility and ETE Revolving Credit Facility contain financial covenants as follows:

- Maximum Leverage Ratio – Consolidated Funded Debt of the Parent Company (as defined) to EBITDA (as defined in the agreements) of the Parent Company of not more than 6.0 to 1, with a permitted increase to 7 to 1 during a specified acquisition period following the close of a specified acquisition; and
- EBITDA to interest expense of not less than 1.5 to 1.

Covenants Related to ETP

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.

The credit agreement relating to the ETP Credit Facility contains covenants that limit (subject to certain exceptions) the ETP's and certain of the ETP'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 ETP 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 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 assets and the payment of dividends and specify a maximum debt to capitalization ratio.

Covenants Related to Regency

The Regency Senior Notes contain various covenants that limit, among other things, Regency's ability, and the ability of certain of its subsidiaries, to:

- incur additional indebtedness;
- pay distributions on, or repurchase or redeem equity interests;
- make certain investments;
- incur liens;
- enter into certain types of transactions with affiliates; and
- sell assets, consolidate or merge with or into other companies.

If the Regency Senior Notes achieve investment grade ratings by both Moody's and S&P and no default or event of default has occurred and is continuing, Regency will no longer be subject to many of the foregoing covenants. The Regency Credit Facility contains the following financial covenants:

- Regency's consolidated EBITDA ratio for any preceding four fiscal quarter period, as defined in the credit agreement governing the Regency Credit Facility, must not exceed 5.00 to 1.
- Regency's consolidated EBITDA to consolidated interest expense, as defined in the credit agreement governing the Regency Credit Facility, must be greater than 2.50 to 1.
- Regency's consolidated senior secured leverage ratio for any preceding four fiscal quarter period, as defined in the credit agreement governing the Regency Credit Facility, must not exceed 3.25 to 1.

The Regency Credit Facility also contains various covenants that limit, among other things, the ability of Regency and RGS to:

- incur indebtedness;
- grant liens;
- enter into sale and leaseback transactions;
- make certain investments, loans and advances;
- dissolve or enter into a merger or consolidation;
- enter into asset sales or make acquisitions;
- enter into transactions with affiliates;
- prepay other indebtedness or amend organizational documents or transaction documents (as defined in the credit agreement governing the Regency Credit Facility);
- issue capital stock or create subsidiaries; or
- engage in any business other than those businesses in which it was engaged at the time of the effectiveness of the Regency Credit Facility or reasonable extensions thereof.

Covenants Related to Southern Union

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 the 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.

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 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

Sunoco Logistics' $1.50 billion credit facility contains various covenants, including limitations on the creation of indebtedness and liens, and other covenants related to the operation and conduct of the business of Sunoco Logistics and its subsidiaries. The credit facility also limits Sunoco Logistics, on a rolling four-quarter basis, to a maximum total consolidated debt to consolidated Adjusted EBITDA ratio, as defined in the underlying credit agreement, of 5.0 to 1, which can generally be increased to 5.5 to 1 during an acquisition period. Sunoco Logistics' ratio of total consolidated debt, excluding net unamortized fair value adjustments, to consolidated Adjusted EBITDA was 2.8 to 1 at December 31, 2013, as calculated in accordance with the credit agreements.

The $35 million credit facility 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, 2013 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 1.12 to 1 and 0.88 to 1, respectively, at December 31, 2013.

Compliance With Our Covenants

Failure to comply with the various restrictive and affirmative covenants of our revolving credit facilities and note agreements could require us or our subsidiaries to pay debt balances prior to scheduled maturity and could negatively impact the subsidiaries ability to incur additional debt and/or our ability to pay distributions.

We and our subsidiaries are required to assess compliance quarterly and were in compliance with all requirements, tests, limitations, and covenants related to our debt agreements as of December 31, 2013.

7. REDEEMABLE PREFERRED UNITS:

ETE Preferred Units

In connection with ETE's acquisition of Regency's general partner in 2010, ETE issued 3,000,000 Preferred Units having an aggregate liquidation preference of $300 million, which were reflected as long-term liabilities in our consolidated balance sheet as of December 31, 2012. The Preferred Units were issued in a private placement at a stated price of $100 per unit and were entitled to a preferential quarterly cash distribution of $2.00 per Preferred Unit.

On April 1, 2013, ETE paid $300 million to redeem (the "Redemption") all of its 3,000,000 outstanding Preferred Units. Prior to the Redemption, on March 28, 2013, ETE paid the holder of the Preferred Units $40 million in cash in exchange for the holder relinquishing its right to receive any premium in connection with a future redemption or conversion of the Preferred Units.

Prior to the April 1, 2013 Redemption, we recorded non-cash charges of approximately $9 million to increase the carrying value of the Preferred Units to the estimated fair value. During 2012, we recorded non-cash charges of approximately $8 million to increase the carrying value of the Preferred Units to the estimated fair value of $331 million as of December 31, 2012.

Preferred Units of Subsidiary

Holders may elect to convert Regency Preferred Units to Regency Common Units at any time. In July 2013, certain holders of the Regency Preferred Units exercised their right to convert an aggregate 2,459,017 Series A Preferred Units into Regency Common Units. Concurrent with this transaction, a gain of $26 million was recognized in other income, net, related to the embedded derivative and reclassified $41 million from the Regency Preferred Units into Regency Common Units. As of December 31, 2013, the remaining Regency Preferred Units were convertible into 2,050,854 Regency Common Units, and if outstanding, are mandatorily redeemable on September 2, 2029 for $35 million plus all accrued but unpaid distributions and interest thereon. The Regency Preferred Units received fixed quarterly cash distributions of $0.445 per unit if outstanding on the record dates of Regency's common unit distributions. Holders can elect to convert Regency Preferred Units into Regency Common Units into common units at any time in accordance with the partnership agreement.

The following table provides a reconciliation of the beginning and ending balances of the Regency Preferred Units:

	Regency Preferred Units	Amount	
Balance at January 1, 2012	4.4	$ 71	
Accretion to redemption value	N/A	2	
Balance, December 31, 2012	4.4	$ 73	
Regency Preferred Units converted into Regency Common Units	(2.5)	(41)	
Balance, December 31, 2013	1.9	$ 32	(1)

(1) This amount will be accreted to $35 million plus any accrued but unpaid distributions and interest by deducting amounts from partners' capital over the remaining periods until the mandatory redemption date of September 2, 2029. Accretion during 2013 was immaterial.

8. EQUITY:

Limited Partner Units

Limited partner interests in the Partnership are represented by Common Units that entitle the holders thereof to the rights and privileges specified in the Partnership Agreement. The Partnership's Common Units are registered under the Securities Exchange Act of 1934 (as amended) and are listed for trading on the NYSE. Each holder of a Common Unit is entitled to one vote per unit on all matters presented to the Limited Partners for a vote. In addition, if at any time any person or group (other than the Partnership's General Partner and its affiliates) owns beneficially 20% or more of all Common Units, any Common Units owned by that person or group may not be voted on any matter and are not considered to be outstanding when sending notices of a meeting of Unitholders (unless otherwise required by law), calculating required votes, determining the presence of a quorum or for other similar purposes under the Partnership Agreement. The Common Units are entitled to distributions of Available Cash as described below under "Parent Company Quarterly Distributions of Available Cash."

As of December 31, 2013, there were issued and outstanding 559.9 million Common Units representing an aggregate 99.48% limited partner interest in the Partnership.

Our Partnership Agreement contains specific provisions for the allocation of net earnings and losses to the partners for purposes of maintaining the partner capital accounts. For any fiscal year that the Partnership has net profits, such net profits are first allocated to the General Partner until the aggregate amount of net profits for the current and all prior fiscal years equals the aggregate amount of net losses allocated to the General Partner for the current and all prior fiscal years. Second, such net profits shall be allocated to the Limited Partners pro rata in accordance with their respective sharing ratios. For any fiscal year in which the Partnership has net losses, such net losses shall be first allocated to the Limited Partners in proportion to their respective adjusted capital account balances, as defined by the Partnership Agreement, (before taking into account such net losses) until their adjusted capital account balances have been reduced to zero. Second, all remaining net losses shall be allocated to the General Partner. The General Partner may distribute to the Limited Partners funds of the Partnership that the

General Partner reasonably determines are not needed for the payment of existing or foreseeable Partnership obligations and expenditures.

Common Units

The change in ETE Common Units during the years ended December 31, 2013, 2012 and 2011was as follows:

	Years Ended December 31,		
	2013	2012	2011
Number of Common Units, beginning of period	559.9	445.9	445.9
Issuance of restricted Common Units under long-term incentive plan	—	—	—
Issuance of common units in connection with Southern Union Merger (See Note 3)	—	114.0	—
Number of Common Units, end of period	559.9	559.9	445.9

Common Unit Split and Repurchase Program

On December 23, 2013, ETE announced that the board of directors of its general partner approved a two-for-one split of the Partnership's outstanding common units (the "Unit Split"). The Unit Split was completed on January 27, 2014. The Unit Split was effected by a distribution of one ETE Common Unit for each common unit outstanding and held by unitholders of record at the close of business on January 13, 2014.

In December 2013, the Partnership announced a common unit repurchase program, whereby the Partnership may repurchase up to $1 billion of ETE Common Units in the open market at the Partnership's discretion, subject to market conditions and other factors, and in accordance with applicable regulatory requirements. The Partnership repurchased 1,695,200 ETE Common Units under this program through February 10, 2014.

Class D Units

On May 1, 2013, Jamie Welch was appointed Group Chief Financial Officer and Head of Corporate Development of LE GP, LLC, the general partner of ETE, effective June 24, 2013. Pursuant to an equity award agreement between Mr. Welch and the Partnership dated April 23, 2013, Mr. Welch received 1,500,000 restricted ETE common units representing limited partner interest. The restricted ETE common units were subject to vesting, based on continued employment with ETE. On December 23, 2013, ETE and Mr. Welch entered into (i) a rescission agreement in order to rescind the original offer letter to the extent it relates to the award of 1,500,000 common units of ETE to Mr. Welch, the original award agreements, and the receipt of cash amounts by Mr. Welch with respect to such awarded units and (ii) a new Class D Unit Agreement between ETE and Mr. Welch providing for the issuance to Mr. Welch of an aggregate of 1,540,000 Class D Units of ETE, which number of Class D Units includes an additional 40,000 Class D Units that were issued to Mr. Welch in connection with other changes to his original offer letter.

Under the terms of the Class D Unit Agreement, 30% of the Class D Units will convert to ETE common units on a one-for-one basis on March 31, 2015, and the remaining 70% will convert to ETE common units on a one-for-one basis on March 31, 2018, subject in each case to (i) Mr. Welch being in Good Standing with ETE (as defined in the Class D Unit Agreement) and (ii) there being a sufficient amount of gain available (based on the ETE partnership agreement) to be allocated to the Class D Units being converted so as to cause the capital account of each such unit to equal the capital account of an ETE Common Unit on the conversion date.

Sale of Common Units by Subsidiaries

The Parent Company accounts for the difference between the carrying amount of its investment in ETP and Regency and the underlying book value arising from issuance of units by ETP or Regency (excluding unit issuances to the Parent Company) as a capital transaction. If ETP or Regency issues units at a price less than the Parent Company's carrying value per unit, the Parent Company assesses whether the investment has been impaired, in which case a provision would be reflected in our statement of operations. The Parent Company did not recognize any impairment related to the issuance of ETP or Regency Common Units during the periods presented.

Sale of Common Units by ETP

The following table summarizes ETP's public offerings of ETP Common Units, all of which have been registered under the Securities Act of 1933 (as amended):

Date	Number of ETP Common Units	Price per ETP Unit	Net Proceeds
April 2011	14.2	$ 50.52	$ 695
November 2011	15.2	44.67	660
July 2012	15.5	44.57	671
April 2013	13.8	48.05	657

Proceeds from the offerings listed above were used to repay amounts outstanding under the ETP Credit Facility and/or to fund capital expenditures and capital contributions to joint ventures, and for general partnership purposes.

ETP's Equity Distribution Program

From time to time, ETP has sold ETP Common Units through an equity distribution agreement. Such sales of ETP Common Units are made by means of ordinary brokers' transactions on the NYSE at market prices, in block transactions or as otherwise agreed between us and the sales agent which is the counterparty to the equity distribution agreement.

In January 2013 and May 2013, ETP entered into equity distribution agreements pursuant to which ETP may sell from time to time ETP Common Units having aggregate offering prices of up to $200 million and $800 million, respectively. During the year ended December 31, 2013, ETP issued approximately 16.9 million ETP Common Units for $846 million, net of commissions of $9 million. Approximately $145 million of ETP Common Units remained available to be issued under the currently effective equity distribution agreement as of December 31, 2013.

ETP's Equity Incentive Plan Activity

As discussed in Note 9, ETP issues ETP Common Units to employees and directors upon vesting of awards granted under ETP's equity incentive plans. Upon vesting, participants in the equity incentive plans may elect to have a portion of the ETP Common Units to which they are entitled withheld by ETP to satisfy tax-withholding obligations.

ETP's Distribution Reinvestment Program

In April 2011, ETP filed a registration statement with the SEC covering its Distribution Reinvestment Plan (the "DRIP"). The DRIP provides ETP's Unitholders of record and beneficial owners of ETP Common Units a voluntary means by which they can increase the number of ETP Common Units they own by reinvesting the quarterly cash distributions they would otherwise receive in the purchase of additional ETP Common Units. The registration statement covers the issuance of up to 5.8 million ETP Common Units under the DRIP.

During the years ended December 31, 2013, 2012 and 2011, aggregate distributions of approximately $109 million, $43 million and $15 million were reinvested under the DRIP resulting in the issuance in aggregate of approximately 3.7 million ETP Common Units. As of December 31, 2013, a total of 2.1 million ETP Common Units remain available to be issued under the existing registration statement.

ETP Class E Units

There are 8.9 million ETP Class E Units outstanding that are reported by ETP as treasury units. These ETP Class E Units are entitled to aggregate cash distributions equal to 11.1% of the total amount of cash distributed to all ETP Unitholders, including the ETP Class E Unitholders, up to $1.41 per unit per year, with any excess thereof available for distribution to ETP Unitholders other than the holders of ETP Class E Units in proportion to their respective interests. The ETP Class E Units are treated by ETP as treasury units for accounting purposes because they are owned by a subsidiary of Holdco, Heritage Holdings, Inc. Although no plans are currently in place, management may evaluate whether to retire some or all of the ETP Class E Units at a future date.

ETP Class G Units

In conjunction with the Sunoco Merger, ETP amended its partnership agreement to create the ETP Class F Units. The number of ETP Class F Units issued was determined at the closing of the Sunoco Merger and equaled 90.7 million, which included

40 million ETP Class F Units issued in exchange for cash contributed by Sunoco to ETP immediately prior to or concurrent with the closing of the Sunoco Merger. The ETP Class F Units generally did not have any voting rights. The ETP Class F Units were entitled to aggregate cash distributions equal to 35% of the total amount of cash generated by ETP and its subsidiaries (other than Holdco) and available for distribution, up to a maximum of $3.75 per ETP Class F Unit per year. In April 2013, all of the outstanding ETP Class F Units were exchanged for ETP Class G Units on a one-for-one basis. The ETP Class G Units have terms that are substantially the same as the ETP Class F Units, with the principal difference between the ETP Class G Units and the ETP Class F Units being that allocations of depreciation and amortization to the ETP Class G Units for tax purposes are based on a predetermined percentage and are not contingent on whether ETP has net income or loss. The ETP Class G Units are held by a subsidiary of ETP and therefore are reflected by ETP as treasury units in its consolidated financial statements.

ETP Class H Units

Pursuant to an Exchange and Redemption Agreement previously entered into between ETP, ETE and ETE Holdings, ETP redeemed and cancelled 50.2 million of its Common Units representing limited partner interests (the “Redeemed Units”) owned by ETE Holdings on October 31, 2013 in exchange for the issuance by ETP to ETE Holdings of a new class of limited partner interest in ETP (the “Class H Units”), which are generally entitled to (i) allocations of profits, losses and other items from ETP corresponding to 50.05% of the profits, losses, and other items allocated to ETP by Sunoco Partners, with respect to the IDRs and general partner interest in Sunoco Logistics held by Sunoco Partners, (ii) distributions from available cash at ETP for each quarter equal to 50.05% of the cash distributed to ETP by Sunoco Partners with respect to the IDRs and general partner interest in Sunoco Logistics held by Sunoco Partners for such quarter and, to the extent not previously distributed to holders of the Class H Units, for any previous quarters and (iii) incremental additional cash distributions in the aggregate amount of $329 million, to be payable by ETP to ETE Holdings over 15 quarters, commencing with the quarter ended September 30, 2013 and ending with the quarter ending March 31, 2017. The incremental cash distributions referred to in clause (iii) of the previous sentence are intended to offset a portion of the IDR subsidies previously granted by ETE to ETP in connection with the Citrus Merger, the Holdco Transaction and the Holdco Acquisition. In connection with the issuance of the Class H Units, ETE and ETP also agreed to certain adjustments to the prior IDR subsidies in order to ensure that the IDR subsidies are fixed amounts for each quarter to which the IDR subsidies are in effect. For a summary of the net IDR subsidy amounts resulting from this transaction, see “Quarterly Distributions of Available Cash” below.

The ETP Class H Units are held by a subsidiary of ETE and therefore are reflected by ETP as treasury units in its consolidated financial statements.

Sale of Common Units by Regency

The following table summarizes Regency’s public offerings of Regency Common Units during the periods presented:

Date	Number of Regency Common Units (1)	Price per Regency Unit	Net Proceeds
May 2011	8.5	(1)	$ 204
October 2011	11.5	$ 20.92	232
March 2012	12.7	24.47	297

(1) Regency Units were issued in a private placement.

Proceeds were used to repay amounts outstanding under the Regency Credit Facility and/or fund capital expenditures and capital contributions to joint ventures, as well as for general partnership purposes.

In June 2012, Regency entered into an Equity Distribution Agreement with Citi under which Regency may offer and sell Regency Common Units, representing limited partner interests, having an aggregate offering price of up to $200 million from time to time through Citi, as sales agent for Regency. Sales of these units, if any, made under the Regency Equity Distribution Agreement will be made by means of ordinary brokers’ transactions on the New York Stock Exchange at market prices, in block transactions, or as otherwise agreed upon by Regency and Citi. Under the terms of this agreement, Regency may also sell Regency Common Units to Citi as principal for its own account at a price agreed upon at the time of sale. Any sale of Regency Common Units to Citi as principal would be pursuant to the terms of a separate agreement between Regency and Citi. Regency intends to use the net proceeds from the sale of these units for general partnership purposes. As of December 31, 2013, Regency received net proceeds of $149 million from Regency Common Units issued pursuant to this Equity Distribution Agreement.

Contributions to Subsidiaries

The Parent Company indirectly owns the entire general partner interest in ETP through its ownership of ETP GP, the general partner of ETP. ETP GP has the right, but not the obligation, to contribute a proportionate amount of capital to ETP to maintain its current general partner interest. ETP GP's interest in ETP's distributions is reduced if ETP issues additional units and ETP GP does not contribute a proportionate amount of capital to ETP to maintain its General Partner interest.

The Parent Company owns the entire general partner interest in Regency through its ownership of Regency GP. Regency GP has the right, but not the obligation, to contribute a proportionate amount of capital to Regency to maintain its current general partner interest. Regency GP's interest in Regency's distributions is reduced if Regency issues additional units and Regency GP does not contribute a proportionate amount of capital to Regency to maintain its General Partner interest.

Parent Company Quarterly Distributions of Available Cash

Our distribution policy is consistent with the terms of our Partnership Agreement, which requires that we distribute all of our available cash quarterly. The Parent Company's only cash-generating assets currently consist of distributions from ETP and Regency related to limited and general partner interests, including IDRs. As of December 31, 2013, we had no independent operations outside of our direct and indirect interests in ETP and Regency.

Our distributions declared during the years ended December 31, 2013, 2012 and 2011 are summarized as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2010	February 7, 2011	February 18, 2011	$ 0.27000
March 31, 2011	May 6, 2011	May 19, 2011	0.28000
June 30, 2011	August 5, 2011	August 19, 2011	0.31250
September 30, 2011	November 4, 2011	November 18, 2011	0.31250
December 31, 2011	February 7, 2012	February 17, 2012	0.31250
March 31, 2012	May 4, 2012	May 18, 2012	0.31250
June 30, 2012	August 6, 2012	August 17, 2012	0.31250
September 30, 2012	November 6, 2012	November 16, 2012	0.31250
December 31, 2012	February 7, 2013	February 19, 2013	0.31750
March 31, 2013	May 6, 2013	May 17, 2013	0.32250
June 30, 2013	August 5, 2013	August 19, 2013	0.32750
September 30, 2013	November 4, 2013	November 19, 2013	0.33625
December 31, 2013	February 7, 2014	February 19, 2014	0.34625

ETP's Quarterly Distribution of Available Cash

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

ETP's distributions declared during the periods presented below are summarized as follows:

Quarter Ended	Record Date	Payment Date	Distribution per ETP Common Unit
December 31, 2010	February 7, 2011	February 14, 2011	$ 0.89375
March 31, 2011	May 6, 2011	May 16, 2011	0.89375
June 30, 2011	August 5, 2011	August 15, 2011	0.89375
September 30, 2011	November 4, 2011	November 14, 2011	0.89375
December 31, 2011	February 7, 2012	February 14, 2012	0.89375
March 31, 2012	May 4, 2012	May 15, 2012	0.89375
June 30, 2012	August 6, 2012	August 14, 2012	0.89375
September 30, 2012	November 6, 2012	November 14, 2012	0.89375
December 31, 2012	February 7, 2013	February 14, 2013	0.89375
March 31, 2013	May 6, 2013	May 15, 2013	0.89375
June 30, 2013	August 5, 2013	August 14, 2013	0.89375
September 30, 2013	November 4, 2013	November 14, 2013	0.90500
December 31, 2013	February 7, 2014	February 14, 2014	0.92000

Following are ETP incentive distributions ETE has agreed to relinquish:

- In conjunction with ETP's Citrus Merger, ETE agreed to relinquish its rights to $220 million of incentive distributions from ETP that ETE would otherwise be entitled to receive over 16 consecutive quarters beginning with the distribution paid on May 15, 2012.
- In conjunction with the Holdco Transaction in October 2012, 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.
- As discussed in Note 3, in connection with the Holdco Acquisition on April 30, 2013, ETE also agreed to relinquish incentive distributions on the newly issued Common Units for the first eight consecutive quarters beginning with the distribution paid on August 14, 2013, and 50% of the incentive distributions for the following eight consecutive quarters.

In addition, the incremental distributions on the Class H Units, which are referred to in "ETP Class H Units" above, were intended to offset a portion of the incentive distribution relinquishments previously granted by ETE to ETP. In connection with the issuance of the ETP Class H Units, ETE and ETP also agreed to certain adjustments to the incremental distributions on the ETP Class H Units in order to ensure that the net impact of the incentive distribution relinquishments (a portion of which is variable) and the incremental distributions on the ETP Class H Units are fixed amounts for each quarter for which the incentive distribution relinquishments and incremental distributions on the ETP Class H Units are in effect.

In addition to the amounts above, in connection with the transfer of Trunkline LNG in February 2014, ETE agreed to relinquish incentive distributions of $50 million, $50 million, $45 million, and $35 million during the years ended December 31, 2016, 2017, 2018 and 2019, respectively.

Following is a summary of the net amounts by which these incentive distribution relinquishments and incremental distributions on ETP Class H Units would reduce the total distributions that would potentially be made to ETE in future quarters:

	Quarters Ending				
	March 31	June 30	September 30	December 31	Total Year
2014	$ 26.50	$ 26.50	$ 26.50	$ 26.50	$ 106.00
2015	12.50	12.50	13.00	13.00	51.00
2016	18.00	18.00	18.00	18.00	72.00
2017	12.50	12.50	12.50	12.50	50.00
2018	11.25	11.25	11.25	11.25	45.00
2019	8.75	8.75	8.75	8.75	35.00

Regency's Quarterly Distribution of Available Cash

Regency's Partnership Agreement requires that Regency distribute all of its Available Cash to its Unitholders and its General Partner within 45 days after the end of each quarter to unitholders of record on the applicable record date, as determined by the general partner. The term Available Cash generally consists of all cash and cash equivalents on hand at the end of that quarter less the amount of cash reserves established by the general partner to: (i) provide for the proper conduct of the Partnership's business; (ii) comply with applicable law, any debt instruments or other agreements; or (iii) provide funds for distributions to the unitholders and to the General Partner for any one or more of the next four quarters and plus, all cash on hand on that date of determination of available cash for the quarter resulting from working capital borrowings made after the end of the quarter for which the determination is being made.

Distributions paid by Regency since the date of acquisition are summarized as follows:

Quarter Ended	Record Date	Payment Date	Distribution per Regency Common Unit
December 31, 2010	February 7, 2011	February 14, 2011	$ 0.445
March 31, 2011	May 6, 2011	May 13, 2011	0.445
June 30, 2011	August 5, 2011	August 12, 2011	0.450
September 30, 2011	November 7, 2011	November 14, 2011	0.455
December 31, 2011	February 6, 2012	February 13, 2012	0.460
March 31, 2012	May 7, 2012	May 14, 2012	0.460
June 30, 2012	August 6, 2012	August 14, 2012	0.460
September 30, 2012	November 6, 2012	November 14, 2012	0.460
December 31, 2012	February 7, 2013	February 14, 2013	0.460
March 31, 2013	May 6, 2013	May 13, 2013	0.460
June 30, 2013	August 5, 2013	August 14, 2013	0.465
September 30, 2013	November 4, 2013	November 14, 2013	0.470
December 31, 2013	February 7, 2014	February 14, 2014	0.475

In conjunction with Southern Union's contributions of SUGS to Regency, ETE agreed to relinquish incentive distributions on the 31.4 million Regency Common Units issued for twenty-four months subsequent to the transaction closing.

Sunoco Logistics Quarterly Distributions of Available Cash

Distributions paid by Sunoco Logistics since the date of acquisition are summarized as follows:

Quarter Ended	Record Date	Payment Date	Distribution per Sunoco Logistics Common Unit
December 31, 2012	February 8, 2013	February 14, 2013	$ 0.5450
March 31, 2013	May 9, 2013	May 15, 2013	0.5725
June 30, 2013	August 8, 2013	August 14, 2013	0.6000
September 30, 2013	November 8, 2013	November 14, 2013	0.6300
December 31, 2013	February 10, 2014	February 14, 2014	0.6625

Accumulated Other Comprehensive Income (Loss)

The following table presents the components of AOCI, net of tax:

	December 31, 2013	December 31, 2012
Net losses on commodity related hedges	$ (4)	$ (3)
Available-for-sale securities	2	—
Foreign currency translation adjustment	(1)	—
Actuarial gain (loss) related to pensions and other postretirement benefits	56	(10)
Equity investments, net	8	(9)
Subtotal	61	(22)
Amounts attributable to noncontrolling interest	(52)	10
Total AOCI included in partners' capital, net of tax	$ 9	$ (12)

The table below sets forth the tax amounts included in the respective components of other comprehensive income (loss):

	December 31, 2013	December 31, 2012
Net gains on commodity related hedges	$ —	$ 2
Actuarial (gain) loss relating to pension and other postretirement benefits	(39)	5
Total	$ (39)	$ 7

9. UNIT-BASED COMPENSATION PLANS:

We, ETP, Sunoco Logistics and Regency have issued equity incentive plans for employees, officers and directors, which provide for various types of awards, including options to purchase Common Units, restricted units, phantom units, distribution equivalent rights ("DERs"), common unit appreciation rights, and other unit-based awards.

ETE Long-Term Incentive Plan

The Board of Directors or the Compensation Committee of the board of directors of the our General Partner (the "Compensation Committee") may from time to time grant additional awards to employees, directors and consultants of ETE's general partner and its affiliates who perform services for ETE. The plan provides for the following types of awards: restricted units, phantom units, unit options, unit appreciation rights and distribution equivalent rights. The number of additional units that may be delivered pursuant to these awards is limited to 6,000,000 units. As of December 31, 2013, 5,693,789 units remain available to be awarded under the plan.

In December 2013, 1,540,000 Class D Units were granted to an ETE employee, Jaime Welch. Under the terms of the Class D Unit Agreement, 30% of the Class D Units granted to Welch will convert to ETE common units on a one-for-one basis on March 31, 2015, and the remaining 70% will convert to ETE common units on a one-for-one basis on March 31, 2018, subject in each case to (i) Mr. Welch being in Good Standing with ETE (as defined in the Class D Unit Agreement) and (ii) there being a sufficient amount of gain available (based on the ETE partnership agreement) to be allocated to the Class D Units being converted so as to cause the capital account of each such unit to equal the capital account of an ETE Common Unit on the conversion date. See further discussion at Note 8 to our consolidated financial statements.

During 2013, no awards were granted to ETE employees except the 1,540,000 Class D Units discussed above and 12,084 ETE units were granted to non-employee directors. Under our equity incentive plans, our non-employee directors each receive grants that vest ratably over three years and do not entitle the holders to receive distributions during the vesting period.

During 2013, a total of 56,048 ETE Common Units vested, with a total fair value of $2.1 million as of the vesting date. As of December 31, 2013, excluding Class D units, a total of 65,980 restricted units granted to ETE employees and directors remain outstanding, for which we expect to recognize a total of less than $1 million in compensation over a weighted average period of 1.7 years. As of December 31, 2013, a total of 1,540,000 Class D Units granted to Mr. Welch remain outstanding, for which we expect to recognize a total of $37 million in compensation over a weighted average period of 3.5 years.

ETP Unit-Based Compensation Plans

Unit Grants

ETP has granted restricted unit awards to employees that vest over a specified time period, typically a five-year service vesting requirement, with vesting based on continued employment as of each applicable vesting date. Upon vesting, ETP Common Units are issued. 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 ETP Common Unit made by ETP on its Common Units promptly following each such distribution by ETP to its Unitholders. We refer to these rights as "distribution equivalent rights." Under ETP's equity incentive plans, ETP's non-employee directors each receive grants with a five-year service vesting requirement.

Award Activity

The following table shows the activity of the ETP awards granted to employees and non-employee directors:

	Number of ETP Units	Weighted Average Grant-Date Fair Value Per ETP Unit
Unvested awards as of December 31, 2012	1.9	$ 46.95
Awards granted	2.1	50.54
Awards vested	(0.6)	45.62
Awards forfeited	(0.2)	45.72
Unvested awards as of December 31, 2013	3.2	49.65

During the years ended December 31, 2013, 2012 and 2011, the weighted average grant-date fair value per unit award granted was $50.54, $43.93 and $48.35, respectively. The total fair value of awards vested was $26 million, $29 million and $27 million, respectively, based on the market price of ETP Common Units as of the vesting date. As of December 31, 2013, a total of 3.2 million unit awards remain unvested, for which ETP expects to recognize a total of $116 million in compensation expense over a weighted average period of 2.1 years.

Sunoco Logistics Unit-Based Compensation Plan

Sunoco Logistics' general partner has a long-term incentive plan for employees and directors, which permits the grant of restricted units and unit options of Sunoco Logistics covering an additional 0.6 million Sunoco common units. As of December 31, 2013, a total of 0.6 million Sunoco Logistics restricted units were outstanding for which Sunoco Logistics expects to recognize $21 million of expense over a weighted-average period of 2.8 years.

Related Party Awards

McReynolds Energy Partners, L.P., the general partner of which is owned and controlled by an ETE officer, awarded to certain officers of ETP certain rights related to units of ETE previously issued by ETE to such ETE officer. These rights include the economic benefits of ownership of these ETE units based on a five-year vesting schedule whereby the ETP officers vested in the ETE units at a rate of 20% per year. As these ETE units 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 were paid by ETP or ETE. As these units were outstanding prior to these awards, these awards did not represent an increase in the number of outstanding units of either ETP or ETE and were not dilutive to cash distributions per unit with respect to either ETP or ETE.

ETP recognized non-cash compensation expense over the vesting period based on the grant-date fair value of the ETE units awarded to the ETP employees assuming no forfeitures. For the years ended December 31, 2013, 2012 and 2011, ETP recognized non-cash compensation expense, net of forfeitures, of less than $1 million, $1 million and $2 million, respectively, as a result of these awards. As of December 31, 2013, no rights related to ETE common units remain outstanding.

Regency Unit-Based Compensation Plans

Regency has the following awards outstanding as of December 31, 2013:

- 142,550 Regency Common Unit options, all of which are exercisable, with a weighted average exercise price of $22.04 per unit option; and
- 982,242 Regency Phantom Units, with a weighted average grant date fair value of $23.16 per Phantom Unit.

Regency expects to recognize $19 million of compensation expense related to the Regency Phantom Units over a period of 3.3 years.

10. INCOME TAXES:

As a partnership, we are not subject to U.S. federal income tax and most state income taxes. However, the partnership conducts certain activities through corporate subsidiaries which are subject to federal and state income taxes. The components of the federal and state income tax expense (benefit) of our taxable subsidiaries were summarized as follows:

	Years Ended December 31,		
	2013	2012	2011
Current expense (benefit):			
Federal	$ 51	$ (3)	$ (1)
State	(1)	6	17
Total	50	3	16
Deferred expense:			
Federal	(14)	41	—
State	57	10	1
Total	43	51	1
Total income tax expense from continuing operations	$ 93	$ 54	$ 17

Historically, our effective tax rate differed from the statutory rate primarily due to partnership earnings that are not subject to U.S. federal and most state income taxes at the partnership level. The completion of the Southern Union, Sunoco and Holdco transactions (see Note 3) significantly increased the activities conducted through corporate subsidiaries. A reconciliation of income tax expense (benefit) at the U.S. statutory rate to the income tax expense (benefit) attributable to continuing operations for the years ended December 31, 2013 and 2012 is as follows:

	December 31, 2013			December 31, 2012		
	Corporate Subsidiaries[(1)]	Partnership[(2)]	Consolidated	Corporate Subsidiaries[(1)]	Partnership[(2)]	Consolidated
Income tax expense (benefit) at U.S. statutory rate of 35 percent	$ (172)	$ —	$ (172)	$ (4)	$ —	$ (4)
Increase (reduction) in income taxes resulting from:						
Nondeductible goodwill	241	—	241	—	—	—
Nondeductible executive compensation	—	—	—	28	—	28
State income taxes (net of federal income tax effects)	31	10	41	9	2	11
Other	(16)	(1)	(17)	19	—	19
Income tax from continuing operations	$ 84	$ 9	$ 93	$ 52	$ 2	$ 54

(1) Includes Holdco, Oasis Pipeline Company, Pueblo, Inland Corporation, Mid-Valley Pipeline Company and West Texas Gulf Pipeline Company. The latter three entities were acquired in the Sunoco Merger. Holdco, which was formed via the Sunoco Merger and the Holdco Transaction (see Note 3), includes Sunoco and Southern Union and their subsidiaries. ETE held a 60% interest in Holdco until April 30, 2013. Subsequent to the Holdco Acquisition (see Note 3) on April 30, 2013, ETP owns 100% of Holdco.

(2) Includes ETE and its respective subsidiaries that are classified as pass-through entities for federal income tax purposes.

Deferred taxes result from the temporary differences between financial reporting carrying amounts and the tax basis of existing assets and liabilities. The table below summarizes the principal components of the deferred tax assets (liabilities) as follows:

	December 31,	
	2013	2012
Deferred income tax assets:		
Net operating losses and alternative minimum tax credit	$ 217	$ 270
Pension and other postretirement benefits	57	127
Long term debt	108	117
Other	104	290
Total deferred income tax assets	486	804
Valuation allowance	(74)	(94)
Net deferred income tax assets	412	710
Deferred income tax liabilities:		
Properties, plants and equipment	(1,624)	(2,026)
Inventory	(302)	(516)
Investments in unconsolidated affiliates	(2,245)	(1,543)
Trademarks	(180)	(192)
Other	(45)	(129)
Total deferred income tax liabilities	(4,396)	(4,406)
Net deferred income tax liability	(3,984)	(3,696)
Less: current portion of deferred income tax assets (liabilities)	(119)	(130)
Accumulated deferred income taxes	$ (3,865)	$ (3,566)

The completion of the Southern Union Merger, Sunoco Merger and Holdco Transaction (see Note 3) significantly increased the deferred tax assets (liabilities). The table below provides a rollforward of the net deferred income tax liability as follows:

	December 31,	
	2013	2012
Net deferred income tax liability, beginning of year	$ (3,696)	$ (214)
Southern Union acquisition	—	(1,428)
Sunoco acquisition	—	(1,989)
SUGS Contribution to Regency	(115)	—
Tax provision (including discontinued operations)	(124)	(62)
Other	(49)	(3)
Net deferred income tax liability	$ (3,984)	$ (3,696)

Holdco and other corporate subsidiaries have gross federal net operating loss carryforwards of $216 million, all of which will expire in 2032. Holdco has $40 million of federal alternative minimum tax credits which do not expire. Holdco and other corporate subsidiaries have state net operating loss carryforward benefits of $101 million, net of federal tax, which expire between 2013 and 2032. The valuation allowance of $74 million is applicable to the state net operating loss carryforward benefits applicable to Sunoco pre-acquisition periods.

The following table sets forth the changes in unrecognized tax benefits:

	Years Ended December 31,		
	2013	2012	2011
Balance at beginning of year	$ 27	$ 2	$ 2
Additions attributable to acquisitions	—	28	—
Additions attributable to tax positions taken in the current year	—	—	1
Additions attributable to tax positions taken in prior years	406	—	—
Settlements	—	—	—
Lapse of statute	(4)	(3)	(1)
Balance at end of year	$ 429	$ 27	$ 2

As of December 31, 2013, we have $425 million ($418 million after federal income tax benefits) related to tax positions which, if recognized, would impact our effective tax rate. We believe it is reasonably possible that its unrecognized tax benefits may be reduced by $6 million ($5 million, net of federal tax) within the next twelve months due to settlement of certain positions.

Sunoco has historically included certain government incentive payments as taxable income on its federal and state income tax returns. In connection with Sunoco’s 2004 through 2011 open statute years, Sunoco has proposed to the IRS that these government incentive payments be excluded from federal taxable income. If Sunoco is fully successful with its claims, it will receive tax refunds of approximately $372 million. However, due to the uncertainty surrounding the claims, a reserve of $372 million was established for the full amount of the claims. Due to the timing of the expected settlement of the claims and the related reserve, the receivable and the reserve for this issue have been netted in the consolidated balance sheet as of December 31, 2013.

Our policy is to accrue interest expense and penalties on income tax underpayments (overpayments) as a component of income tax expense. During 2013, we recognized interest and penalties of less than $1 million. At December 31, 2013, we have interest and penalties accrued of $6 million, net of tax.

In general, ETE and its subsidiaries are no longer subject to examination by the IRS for tax years prior to 2009, except Sunoco, Regency and Pueblo which are no longer subject to examination by the IRS for tax years prior to 2007 and Southern Union which is no longer subject to examination by the IRS for tax years prior to and 2004.

Sunoco has been examined by the IRS for the 2007 and 2008 tax years, however, the statutes remain open for both of these tax years due to carryback of net operating losses. Sunoco is currently under examination for the years 2009 through 2011, but due to the aforementioned carryback, such years also impact Sunoco’s tax liability for the years 2004 through 2008. With the exception of the claims regarding government incentive payments discussed above, all issues are resolved. Southern Union is under examination for the tax years 2004 through 2009. As of December 31, 2013, the IRS has proposed only one adjustment for the years under examination. For the 2006 tax year, the IRS is challenging $545 million of the $690 million of deferred gain associated with a like kind exchange involving certain assets of its distribution operations and its gathering and processing operations. We will vigorously defend and believe Southern Union’s tax position will prevail against this challenge by the IRS. Accordingly, no unrecognized tax benefit has been recorded with respect to this tax position. Regency is also under examination by the IRS for the 2007 and 2008 tax years. The IRS has proposed adjustments in both of these examinations which are under review at the Appeals level. We believe Regency will prevail against this challenge by the IRS. Accordingly, no unrecognized tax benefit has been recorded with respect to these tax positions. The proposed adjustments with respect to Regency would not have a material impact upon our financial statements.

ETE and its subsidiaries also have various state and local income tax returns in the process of examination or administrative appeal in various jurisdictions. We believe the appropriate accruals or unrecognized tax benefits have been recorded for any potential assessment with respect to these examinations.

11. REGULATORY MATTERS, COMMITMENTS, CONTINGENCIES AND ENVIRONMENTAL LIABILITIES:

FERC Audit

The FERC recently completed an audit of PEPL, a subsidiary of Southern Union, for the period from January 1, 2010 through December 31, 2011, to evaluate its compliance with the Uniform System of Accounts as prescribed by the FERC, annual and quarterly financial reporting to the FERC, reservation charge crediting policy and record retention. An audit report was received in August 2013 noting no issues that would have a material impact on the Partnership's historical financial position or results of operations.

Florida Gas Pipeline Relocation Costs

The Florida Department of Transportation, Florida's Turnpike Enterprise ("FDOT/FTE") has various turnpike/State Road 91 widening projects that have impacted or may, over time, impact one or more of FGTs' mainline pipelines located in FDOT/FTE rights-of-way. Certain FDOT/FTE projects have been or are the subject of litigation in Broward County, Florida. On November 16, 2012, FDOT paid to FGT the sum of approximately $100 million, representing the amount of the judgment, plus interest, in a case tried in 2011.

On April 14, 2011, FGT filed suit against the FDOT/FTE and other defendants in Broward County, Florida seeking an injunction and damages as the result of the construction of a mechanically stabilized earth wall and other encroachments in FGT easements as part of FDOT/FTE's I-595 project. On August 21, 2013, FGT and FDOT/FTE entered into a settlement agreement pursuant to which, among other things, FDOT/FTE paid FGT approximately $19 million in September, 2013 in settlement of FGT's claims with respect to the I-595 project. The settlement agreement also provided for agreed easement widths for FDOT/FTE right-of-way and for cost sharing between FGT and FDOT/FTE for any future relocations. Also in September 2013, FDOT/FTE paid FGT an additional approximate $1 million for costs related to the aforementioned turnpike/State Road 91 case tried in 2011.

FGT will continue to seek rate recovery in the future for these types of costs to the extent not reimbursed by the FDOT/FTE. There can be no assurance that FGT will be successful in obtaining complete reimbursement for any such relocation costs from the FDOT/FTE or from its customers or that the timing of such reimbursement will fully compensate FGT for its costs.

Contingent Residual Support Agreement — AmeriGas

In connection with the closing of the contribution of ETP's propane operations in January 2012, ETP agreed to provide contingent, residual support of $1.55 billion of intercompany borrowings made by AmeriGas and certain of its affiliates with maturities through 2022 from a finance subsidiary of AmeriGas that have maturity dates and repayment terms that mirror those of an equal principal amount of senior notes issued by this finance company subsidiary to third party purchases.

PEPL Holdings Guarantee of Collection

In connection with the SUGS Contribution, Regency issued $600 million of 4.50% Senior Notes due 2023 (the "Regency Debt"), the proceeds of which were used by Regency to fund the cash portion of the consideration, as adjusted, and pay certain other expenses or disbursements directly related to the closing of the SUGS Contribution. In connection with the closing of the SUGS Contribution on April 30, 2013, Regency entered into an agreement with PEPL Holdings, a subsidiary of Southern Union, pursuant to which PEPL Holdings provided a guarantee of collection (on a nonrecourse basis to Southern Union) to Regency and Regency Energy Finance Corp. with respect to the payment of the principal amount of the Regency Debt through maturity in 2023. In connection with the completion of the Panhandle Merger, in which PEPL Holdings was merged with and into Panhandle, the guarantee of collection for the Regency Debt was assumed by Panhandle.

NGL Pipeline Regulation

Lone Star has interests in NGL pipelines located in Texas and New Mexico. Lone Star commenced the interstate transportation of NGLs in 2013, which is subject to the jurisdiction of the FERC under the ICA and the Energy Policy Act of 1992. Under the ICA, tariffs must be just and reasonable and not unduly discriminatory or confer any undue preference. The tariff rates established for interstate services were based on a negotiated agreement; however, the FERC's rate-making methodologies may limit our ability to set rates based on our actual costs, may delay or limit the use of rates that reflect increased costs and may subject us to potentially burdensome and expensive operational, reporting and other requirements. Any of the foregoing could adversely affect our business, revenues and cash flow.

Commitments

In the normal course of business, ETP and Regency purchase, process and sell natural gas pursuant to long-term contracts and enter into long-term transportation and storage agreements. Such contracts contain terms that are customary in the industry. We believe that the terms of these agreements are commercially reasonable and will not have a material adverse effect on its financial position or results of operations.

We have certain non-cancelable leases for property and equipment, which require fixed monthly rental payments and expire at various dates through 2056. Rental expense under these operating leases has been included in operating expenses in the accompanying statements of operations and totaled approximately $151 million, $60 million and $29 million for the years ended December 31, 2013, 2012 and 2011, respectively, which include contingent rentals totaling $22 million and $6 million in 2013 and 2012, respectively. During the years ended December 31, 2013, and 2012, approximately $24 million and $4 million, respectively, of rental expense was recovered through related sublease rental income.

Future minimum lease commitments for such leases are:

Years Ending December 31:		
2014	$	83
2015		81
2016		72
2017		68
2018		55
Thereafter		454
Future minimum lease commitments		813
Less: Sublease rental income		(57)
Net future minimum lease commitments	$	756

ETP and Regency's joint venture agreements require that they fund their proportionate share of capital contributions to their unconsolidated affiliates. Such contributions will depend upon their unconsolidated affiliates' capital requirements, such as for funding capital projects or repayment of long-term obligations.

Litigation and Contingencies

We may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business. Natural gas and crude are flammable and combustible. Serious personal injury and significant property damage can arise in connection with their transportation, storage or use. In the ordinary course of business, we are sometimes threatened with or named as a defendant in various lawsuits seeking actual and punitive damages for product liability, personal injury and property damage. We maintain liability insurance with insurers in amounts and with coverage and deductibles management believes are reasonable and prudent, and which are generally accepted in the industry. However, there can be no assurance that the levels of insurance protection currently in effect will continue to be available at reasonable prices or that such levels will remain adequate to protect us from material expenses related to product liability, personal injury or property damage in the future.

Sunoco Litigation

Following the announcement of the Sunoco Merger on April 30, 2012, eight putative class action and derivative complaints were filed in connection with the Sunoco Merger in the Court of Common Pleas of Philadelphia County, Pennsylvania. Each complaint names as defendants the members of Sunoco's board of directors and alleges that they breached their fiduciary duties by negotiating and executing, through an unfair and conflicted process, a merger agreement that provides inadequate consideration and that contains impermissible terms designed to deter alternative bids. Each complaint also names as defendants Sunoco, ETP, ETP GP, ETP LLC, and Sam Acquisition Corporation, alleging that they aided and abetted the breach of fiduciary duties by Sunoco's directors; some of the complaints also name ETE as a defendant on those aiding and abetting claims. In September 2012, all of these lawsuits were settled with no payment obligation on the part of any of the defendants following the filing of Current Reports on Form 8-K that included additional disclosures that were incorporated by reference into the proxy statement related to the Sunoco Merger. Subsequent to the settlement of these cases, the plaintiffs' attorneys sought compensation from Sunoco for attorneys' fees related to their efforts in obtaining these additional disclosures. In January 2013, Sunoco entered into agreements to compensate the plaintiffs' attorneys in the state court actions in the aggregate amount of not more than $950,000 and to compensate the plaintiffs' attorneys in the federal court action in the amount of not more than $250,000. The payment of $950,000 was made in July 2013.

Litigation Relating to the Southern Union Merger

In June 2011, several putative class action lawsuits were filed in the Judicial District Court of Harris County, Texas naming as defendants the members of the Southern Union Board, as well as Southern Union and ETE. The lawsuits were styled *Jaroslawicz v. Southern Union Company, et al.*, Cause No. 2011-37091, in the 333rd Judicial District Court of Harris County, Texas and *Magda v. Southern Union Company, et al.*, Cause No. 2011-37134, in the 11th Judicial District Court of Harris County, Texas. The lawsuits were consolidated into an action styled *In re: Southern Union Company*; Cause No. 2011-37091, in the 333rd Judicial District Court of Harris County, Texas. Plaintiffs allege that the Southern Union directors breached their fiduciary duties to Southern Union's stockholders in connection with the Merger and that Southern Union and ETE aided and abetted the alleged breaches of fiduciary duty. The amended petitions allege that the Merger involves an unfair price and an inadequate sales process, that Southern Union's directors entered into the Merger to benefit themselves personally, including through consulting and noncompete agreements, and that defendants have failed to disclose all material information related to the Merger to Southern Union stockholders. The amended petitions seek injunctive relief, including an injunction of the Merger, and an award of attorneys' and other fees and costs, in addition to other relief. On October 21, 2011, the court denied ETE's October 13, 2011, motion to stay the Texas proceeding in favor of cases pending in the Delaware Court of Chancery.

Also in June 2011, several putative class action lawsuits were filed in the Delaware Court of Chancery naming as defendants the members of the Southern Union Board, as well as Southern Union and ETE. Three of the lawsuits also named Merger Sub as a defendant. These lawsuits are styled: *Southeastern Pennsylvania Transportation Authority, et al. v. Southern Union Company, et al.*, C.A. No. 6615-CS; *KBC Asset Management NV v. Southern Union Company, et al.*, C.A. No. 6622-CS; *LBBW Asset Management Investment GmbH v. Southern Union Company, et al.*, C.A. No. 6627-CS; and *Memo v. Southern Union Company, et al.*, C.A. No. 6639-CS. These cases were consolidated with the following style: *In re Southern Union Co. Shareholder Litigation*, C.A. No. 6615-CS, in the Delaware Court of Chancery. The consolidated complaint asserts similar claims and allegations as the Texas state-court consolidated action. On July 25, 2012, the Delaware plaintiffs filed a notice of voluntary dismissal of all claims without prejudice. In the notice, plaintiffs stated their claims were being dismissed to avoid duplicative litigation and indicated their intent to join the Texas case.

On September 18, 2013, the plaintiff dismissed without prejudice its lawsuit against all defendants.

MTBE Litigation

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 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 also seek natural resource damages, injunctive relief, punitive damages and attorneys' fees.

As of December 31, 2013, Sunoco is a defendant in seven cases, one of which was initiated by the State of New Jersey and two others by the Commonwealth of Puerto Rico with the more recent Puerto Rico action being a companion case alleging damages for additional sites beyond those at issue in the initial Puerto Rico action. Six of these cases are venued in a multidistrict litigation ("MDL") proceeding in a New York federal court. The most recently filed Puerto Rico action is expected to be transferred to the MDL. The New Jersey and Puerto Rico 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.

Fact discovery has concluded with respect to an initial set of fewer than 20 sites each that will be the subject of the first trial phase in the New Jersey case and the initial Puerto Rico case. Insufficient information has been developed about the plaintiffs' legal theories or the facts with respect to statewide natural resource damage claims to provide an analysis of the ultimate potential liability of Sunoco in these matters; however, it is reasonably possible that a loss may be realized. Management believes that an adverse determination with respect to one or more of the MTBE cases could have a significant impact on results of operations during the period in which any said adverse determination occurs, but does not believe that any such adverse determination would have a material adverse effect on the Partnership's consolidated financial position.

Litigation Relating to the PVR Merger

Five putative class action lawsuits challenging the PVR Acquisition are currently pending. All of these cases name PVR, PVR GP and the current directors of PVR GP, as well as the Partnership and the General Partner (collectively, the "Regency Defendants"), as defendants. Each of the lawsuits has been brought by a purported unitholder of PVR, both individually and on behalf of a putative class consisting of public unitholders of PVR. The lawsuits generally allege, among other things, that the directors of PVR GP breached their fiduciary duties to unitholders of PVR, that PVR GP, PVR and the Regency Defendants aided and abetted the directors of PVR GP in the alleged breach of these fiduciary duties, and, as to the actions in federal court, that some or all of PVR, PVR GP, and the directors of PVR GP violated Section 14(a) of the Exchange Act and Rule 14a-9 promulgated thereunder and Section 20(a) of the Exchange Act. The lawsuits purport to seek, in general, (i) injunctive relief, (ii) disclosure of certain additional information concerning the transaction, (iii) in the event the merger is consummated, rescission or an award of rescissory damages, (iv) an award of plaintiffs' costs and (v) the accounting for damages allegedly causes by the defendants to these actions, and, (iv) such further relief as the court deems just and proper. The styles of the pending cases are as follows: David Naiditch v. PVR Partners, L.P., et al. (Case No. 9015-VCL) in the Court of Chancery of the State of Delaware); Charles Monatt v. PVR Partners, LP, et al. (Case No. 2013-10606) and Saul Srour v. PVR Partners, L.P., et al. (Case No. 2013-011015), each pending in the Court of Common Pleas for Delaware County, Pennsylvania; Stephen Bushansky v. PVR Partners, L.P., et al. (C.A. No. 2:13-cv-06829-HB); and Mark Hinnau v. PVR Partners, L.P., et al. (C.A. No. 2:13-cv-07496-HB), pending in the United States District Court for the Eastern District of Pennsylvania.

On January 28, 2014, the defendants entered into a Memorandum of Understanding ("MOU") with Monatt, Srour, Bushansky, Naiditch and Hinnau pursuant to which defendants and the referenced plaintiffs agreed in principle to a settlement of their lawsuits ("Settled Lawsuits"), which will be memorialized in a separate settlement agreement, subject to customary conditions, including consummation of the PVR Acquisition, completion of certain confirmatory discovery, class certification and final approval by the Court of Common Pleas for Delaware County, Pennsylvania. If the Court approves the settlement, the Settled Lawsuits will be dismissed with prejudice and all defendants will be released from any and all claims relating to the Settled Lawsuits.

The settlement will not affect any provisions of the merger agreement or the form or amount of consideration to be received by PVR unitholders in the PVR Acquisition. The defendants have denied and continue to deny any wrongdoing or liability with respect to the plaintiffs' claims in the aforementioned litigation and have entered into the settlement to eliminate the uncertainty, burden, risk, expense, and distraction of further litigation.

Other Litigation and Contingencies

In November 2011, a derivative lawsuit was filed in the Judicial District Court of Harris County, Texas naming as defendants ETP, ETP GP, ETP LLC, the boards of directors of ETP LLC (collectively with ETP GP and ETP LLC, the "ETP Defendants"), certain members of management for ETP and ETE, ETE, and Southern Union. The lawsuit is styled W. J. Garrett Trust v. Bill W. Byrne, et al., Cause No. 2011-71702, in the 157th Judicial District Court of Harris County, Texas. Plaintiffs assert claims for breaches of fiduciary duty, breaches of contractual duties, and acts of bad faith against each of the ETP Defendants and the individual defendants. Plaintiffs also assert claims for aiding and abetting and tortious interference with contract against Southern Union. On October 5, 2012, certain defendants filed a motion for summary judgment with respect to the primary allegations in this action. On December 13, 2012, Plaintiffs filed their opposition to the motion for summary judgment. Defendants filed a reply on December 19, 2012. On December 20, 2012, the court conducted an oral hearing on the motion. Plaintiffs filed a post-hearing sur-reply on January 7, 2013. On January 16, 2013, the Court granted defendants' motion for summary judgment. The parties agreed to settle the matter and executed a memorandum of understanding. On October 4, 2013, the Court approved the settlement and ordered the case dismissed with prejudice.

We or our subsidiaries are a party to various legal proceedings and/or regulatory proceedings incidental to our businesses. For each of these matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies, the likelihood of an unfavorable outcome and the availability of insurance coverage. If we determine that an unfavorable outcome of a particular matter is probable and can be estimated, we accrue the contingent obligation, as well as any expected insurance recoverable amounts related to the contingency. As of December 31, 2013 and 2012, accruals of approximately $46 million and $42 million, respectively, were reflected on our balance sheets related to these contingent obligations. As new information becomes available, our estimates may change. The impact of these changes may have a significant effect on our results of operations in a single period.

The outcome of these matters cannot be predicted with certainty, and there can be no assurance that the outcome of a particular matter will not result in the payment of amounts that have not been accrued for the matter. Furthermore, we may revise accrual amounts prior to the resolution of a particular contingency based on changes in facts and circumstances or in the expected outcome.

No amounts have been recorded in our December 31, 2013 or 2012 consolidated balance sheets for contingencies and current litigation, other than amounts disclosed herein.

Litigation Related to Incident at JJ's Restaurant. On February 19, 2013, there was a natural gas explosion at JJ's Restaurant located at 910 W. 48th Street in Kansas City, Missouri. Effective September 1, 2013, Laclede Gas Company, a subsidiary of The Laclede Group, Inc. ("Laclede"), assumed any and all liability arising from this incident in ETP's sale of the assets of MGE to Laclede.

Attorney General of the Commonwealth of Massachusetts v New England Gas Company. On July 7, 2011, the Massachusetts Attorney General filed a regulatory complaint with the MDPU against New England Gas Company with respect to certain environmental cost recoveries. The Attorney General is seeking a refund to New England Gas Company customers for alleged "excessive and imprudently incurred costs" related to legal fees associated with Southern Union's environmental response activities. In the complaint, the Attorney General requests that the MDPU initiate an investigation into the New England Gas

Company's collection and reconciliation of recoverable environmental costs including: (i) the prudence of any and all legal fees, totaling approximately $19 million, that were charged by the Kasowitz, Benson, Torres & Friedman firm and passed through the recovery mechanism since 2005, the year when a partner in the firm, Southern Union's Vice Chairman, President and COO, joined Southern Union's management team; (ii) the prudence of any and all legal fees that were charged by the Bishop, London & Dodds firm and passed through the recovery mechanism since 2005, the period during which a member of the firm served as Southern Union's Chief Ethics Officer; and (iii) the propriety and allocation of certain legal fees charged that were passed through the recovery mechanism that the Attorney General contends only would qualify for a lesser, 50%, level of recovery. Southern Union has filed its answer denying the allegations and moved to dismiss the complaint, in part on a theory of collateral estoppel. The hearing officer has deferred consideration of Southern Union's motion to dismiss. The AG's motion to be reimbursed expert and consultant costs by Southern Union of up to $150,000 was granted. By tariff, these costs are recoverable through rates charged to New England Gas Company customers. The hearing officer previously stayed discovery pending resolution of a dispute concerning the applicability of attorney-client privilege to legal billing invoices. The MDPU issued an interlocutory order on June 24, 2013 that lifted the stay, and discovery has resumed. Southern Union believes it has complied with all applicable requirements regarding its filings for cost recovery and has not recorded any accrued liability; however, Southern Union will continue to assess its potential exposure for such cost recoveries as the matter progresses.

Air Quality Control. SUGS is currently negotiating settlements to certain enforcement actions by the NMED and the TCEQ. The TCEQ recently initiated a state-wide emissions inventory for the sulfur dioxide emissions from sites with reported emissions of 10 tons per year or more. If this data demonstrates that any source or group of sources may cause or contribute to a violation of the National Ambient Air Quality Standards, they must be sufficiently controlled to ensure timely attainment of the standard. This may potentially affect three SUGS recovery units in Texas. It is unclear at this time how the NMED will address the sulfur dioxide standard.

Compliance Orders from the New Mexico Environmental Department. SUGS has been in discussions with the NMED concerning allegations of violations of New Mexico air regulations related to the Jal #3 and Jal #4 facilities. Hearings on the compliance orders were delayed until March 2014 to allow the parties to pursue substantive settlement discussions. SUGS has meritorious defenses to the NMED claims and can offer significant mitigating factors to the claimed violations. SUGS has recorded a liability of less than $1 million related to the claims and will continue to assess its potential exposure to the allegations as the matter progresses.

Environmental Matters

Our operations are subject to extensive federal, state and local environmental and safety laws and regulations that require expenditures to ensure compliance, including related to air emissions and wastewater discharges, at operating facilities and for remediation at current and former facilities as well as waste disposal sites. Although we believe our operations are in substantial compliance with applicable environmental laws and regulations, risks of additional costs and liabilities are inherent in the business of transporting, storing, gathering, treating, compressing, blending and processing natural gas, natural gas liquids and other products. As a result, there can be no assurance that significant costs and liabilities will not be incurred. Costs of planning, designing, constructing and operating pipelines, plants and other facilities must incorporate compliance with environmental laws and regulations and safety standards. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, the issuance of injunctions and the filing of federally authorized citizen suits. Contingent losses related to all significant known environmental matters have been accrued and/or separately disclosed. However, we may revise accrual amounts prior to resolution of a particular contingency based on changes in facts and circumstances or changes in the expected outcome.

Environmental exposures and liabilities are difficult to assess and estimate due to unknown factors such as the magnitude of possible contamination, the timing and extent of remediation, the determination of our liability in proportion to other parties, improvements in cleanup technologies and the extent to which environmental laws and regulations may change in the future. Although environmental costs may have a significant impact on the results of operations for any single period, we believe that such costs will not have a material adverse effect on our financial position.

Based on information available at this time and reviews undertaken to identify potential exposure, we believe the amount reserved for environmental matters is adequate to cover the potential exposure for cleanup costs.

Environmental Remediation

Our subsidiaries are responsible for environmental remediation at certain sites, including the following:

- Certain of our interstate pipelines conduct soil and groundwater remediation related to contamination from past uses of PCBs. PCB assessments are ongoing and, in some cases, our subsidiaries could potentially be held responsible for contamination caused by other parties.
- Certain gathering and processing systems are responsible for soil and groundwater remediation related to releases of hydrocarbons.
- Southern Union's distribution operations are responsible for soil and groundwater remediation at certain sites related to manufactured gas plants ("MGPs") and may also be responsible for the removal of old MGP structures.
- Currently operating Sunoco retail sites.
- Legacy sites related to Sunoco, 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.
- Sunoco is potentially subject to joint and several liability for the costs of remediation at sites at which it has been identified as a "potentially responsible party" ("PRP"). As of December 31, 2013, Sunoco had been named as a PRP at 40 identified or potentially identifiable as "Superfund" sites under federal and/or comparable state law. Sunoco is usually one of a number of companies identified as a PRP at a site. Sunoco has reviewed the nature and extent of its involvement at each site and other relevant circumstances and, based upon Sunoco's purported nexus to the sites, believes that its potential liability associated with such sites will not be significant.

To the extent estimable, expected remediation costs are included in the amounts recorded for environmental matters in our consolidated balance sheets. In some circumstances, future costs cannot be reasonably estimated because remediation activities are undertaken as claims are made by customers and former customers. To the extent that an environmental remediation obligation is recorded by a subsidiary that applies regulatory accounting policies, amounts that are expected to be recoverable through tariffs or rates are recorded as regulatory assets on our consolidated balance sheets.

The table below reflects the amounts of accrued liabilities recorded in our consolidated balance sheets related to environmental matters that are considered to be probable and reasonably estimable. Except for matters discussed above, we do not have any material environmental matters assessed as reasonably possible that would require disclosure in our consolidated financial statements.

	December 31,	
	2013	2012
Current	$ 47	$ 46
Non-current	356	166
Total environmental liabilities	$ 403	$ 212

In 2013, we have established a wholly-owned captive insurance company to bear certain risks associated with environmental obligations related to certain sites that are no longer operating. The premiums paid to the captive insurance company include estimates for environmental claims that have been incurred but not reported, based on an actuarially determined fully developed claims expense estimate. In such cases, we accrue losses attributable to unasserted claims based on the discounted estimates that are used to develop the premiums paid to the captive insurance company.

During the years ended December 31, 2013 and 2012, the Partnership recorded $41 million and $12 million, respectively, of expenditures related to environmental cleanup programs.

The EPA's Spill Prevention, Control and Countermeasures program regulations were recently modified and impose additional requirements on many of our facilities. We expect to expend resources on tank integrity testing and any associated corrective actions as well as potential upgrades to containment structures to comply with the new rules. Costs associated with tank integrity testing and resulting corrective actions cannot be reasonably estimated at this time, but we believe such costs will not have a material adverse effect on our financial position, results of operations or cash flows.

On August 20, 2010, the EPA published new regulations under the federal Clean Air Act ("CAA") to control emissions of hazardous air pollutants from existing stationary reciprocal internal combustion engines. The rule will require us to undertake certain expenditures and activities, likely including purchasing and installing emissions control equipment. In response to an industry group legal challenge to portions of the rule in the U.S. Court of Appeals for the D.C. Circuit and a Petition for Administrative Reconsideration to the EPA, on March 9, 2011, the EPA issued a new proposed rule and direct final rule effective on May 9, 2011 to clarify compliance requirements related to operation and maintenance procedures for continuous parametric monitoring systems. If no further changes to the standard are made as a result of comments to the proposed rule, we would not expect that the cost to comply with the rule's requirements will have a material adverse effect on our financial condition or results of operations. Compliance with the final rule was required by October 2013, and the Partnership believes it is in compliance.

On June 29, 2011, the EPA finalized a rule under the CAA that revised the new source performance standards for manufacturers, owners and operators of new, modified and reconstructed stationary internal combustion engines. The rule became effective on August 29, 2011. The rule modifications may require us to undertake significant expenditures, including expenditures for purchasing, installing, monitoring and maintaining emissions control equipment, if we replace equipment or expand existing facilities in the future. At this point, we are not able to predict the cost to comply with the rule's requirements, because the rule applies only to changes we might make in the future.

Our pipeline operations are subject to regulation by the DOT under the PHMSA, pursuant to which the PHMSA has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. Moreover, the PHMSA, through the Office of Pipeline Safety, has promulgated a rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline operations 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. 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 future capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines; however, no estimate can be made at this time of the likely range of such expenditures.

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

12. PRICE RISK MANAGEMENT ASSETS AND LIABILITIES:

Commodity Price Risk

We are exposed to market risks related to the volatility of commodity prices. To manage the impact of volatility from these prices, our subsidiaries utilize various exchange-traded and OTC commodity financial instrument contracts. These contracts consist primarily of futures, swaps and options and are recorded at fair value in our consolidated balance sheets. Following is a description of price risk management activities by segment.

ETP

ETP injects and holds natural gas in its Bammel storage facility to take advantage of contango markets (i.e., when the price of natural gas is higher in the future than the current spot price). ETP uses financial derivatives to hedge the natural gas held in connection with these arbitrage opportunities. At the inception of the hedge, ETP locks in a margin by purchasing gas in the spot market or off peak season and entering into a financial contract to lock in the sale price. If ETP designates the related financial contract as a fair value hedge for accounting purposes, ETP values the hedged natural gas inventory at current spot market prices along with the financial derivative ETP uses to hedge it. Changes in the spread between the forward natural gas prices designated as fair value hedges and the physical 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. 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 price and forward natural gas prices. If the spread narrows between the physical and financial prices, ETP will record unrealized gains or lower unrealized losses. If the spread widens, ETP will record unrealized losses or lower unrealized gains. Typically, as ETP enters the winter months, the spread converges so that we recognize in earnings the original locked-in spread through either mark-to-market adjustments or the physical withdraw of natural gas.

ETP is also exposed to market risk on natural gas it retains for fees in its intrastate transportation and storage operations and operational gas sales on its interstate transportation and storage operations. ETP uses financial derivatives to hedge the sales price of this gas, including futures, swaps and options. Certain contracts that qualify for hedge accounting are designated as cash flow hedges of the forecasted sale of natural gas. The change in value, to the extent the contracts are effective, remains in AOCI 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.

ETP is also exposed to commodity price risk on NGLs and residue gas it retains for fees in its midstream operations whereby its subsidiaries generally 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 for the residue gas and NGLs. ETP uses NGL and crude derivative swap contracts to hedge forecasted sales of NGL and condensate equity volumes. Certain contracts that qualify for hedge accounting are accounted for as cash flow hedges. The change in value, to the extent the contracts are effective, remains in AOCI 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.

ETP may use derivatives in ETP’s NGL transportation and services operations to manage ETP’s storage facilities and the purchase and sale of purity NGLs.

Sunoco Logistics utilizes derivatives such as swaps, futures and other derivative instruments to mitigate the risk associated with market movements in the price of refined products and NGLs. These derivative contracts act as a hedging mechanism against the volatility of prices by allowing Sunoco Logistics to transfer this price risk to counterparties who are able and willing to bear it. Since the first quarter 2013, Sunoco Logistics has not designated any of its derivative contracts as hedges for accounting purposes. Therefore, all realized and unrealized gains and losses from these derivative contracts are recognized in the consolidated statements of operations during the current period.

ETP’s trading activities include the use of financial commodity derivatives to take advantage of market opportunities. These trading activities are a complement to its transportation and storage operations and are netted in cost of products sold in the consolidated statements of operations. Additionally, ETP also has trading activities related to power and natural gas in its other operations which are also netted in cost of products sold. As a result of its trading activities and the use of derivative financial instruments in its transportation and storage operations, the degree of earnings volatility that can occur may be significant, favorably or unfavorably, from period to period. ETP attempts to manage this volatility through the use of daily position and profit and loss reports provided to our risk oversight committee, which includes members of senior management, and the limits and authorizations set forth in ETP’s commodity risk management policy.

Derivatives are utilized in ETP’s other operations in order to mitigate price volatility and manage fixed price exposure incurred from contractual obligations. ETP attempts to maintain balanced positions in its marketing activities to protect against volatility in the energy commodities markets; however, net unbalanced positions can exist.

The following table details ETP's outstanding commodity-related derivatives:

	December 31, 2013		December 31, 2012	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark-to-Market Derivatives				
(Trading)				
Natural Gas (MMBtu):				
Fixed Swaps/Futures	9,457,500	2014-2019	—	—
Basis Swaps IFERC/NYMEX [(1)]	(487,500)	2014-2017	(30,980,000)	2013-2014
Swing Swaps	1,937,500	2014-2016	—	—
Power (Megawatt):				
Forwards	351,050	2014	19,650	2013
Futures	(772,476)	2014	(1,509,300)	2013
Options — Puts	(52,800)	2014	—	—
Options — Calls	103,200	2014	1,656,400	2013
Crude (Bbls) – Futures	103,000	2014	—	—
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	570,000	2014	150,000	2013
Swing Swaps IFERC	(9,690,000)	2014-2016	(83,292,500)	2013
Fixed Swaps/Futures	(8,195,000)	2014-2015	27,077,500	2013
Forward Physical Contracts	5,668,559	2014-2015	11,689,855	2013-2014
Natural Gas Liquid (Bbls) – Forwards/Swaps	(280,000)	2014	(30,000)	2013
Refined Products (Bbls) – Futures	(1,133,600)	2014	(666,000)	2013
Fair Value Hedging Derivatives				
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	(7,352,500)	2014	(18,655,000)	2013
Fixed Swaps/Futures	(50,530,000)	2014	(44,272,500)	2013
Hedged Item — Inventory	50,530,000	2014	44,272,500	2013
Cash Flow Hedging Derivatives				
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	(1,825,000)	2014	—	—
Fixed Swaps/Futures	(12,775,000)	2014	(8,212,500)	2013
Natural Gas Liquid (Bbls) – Forwards/Swaps	(780,000)	2014	(930,000)	2013
Refined Products (Bbls) – Futures	—	—	(98,000)	2013
Crude (Bbls) – Futures	(30,000)	2014	—	—

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

We expect gains of $4 million related to ETP's commodity derivatives to be reclassified into earnings over the next 12 months related to amounts currently reported in AOCI. The amount ultimately realized, however, will differ as commodity prices change and the underlying physical transaction occurs.

Regency

Regency is a net seller of NGLs, condensate and natural gas as a result of its gathering and processing operations. The prices of these commodities are impacted by changes in the supply and demand as well as market forces. Regency's profitability and cash flow are affected by the inherent volatility of these commodities, which could adversely affect its ability to make distributions to its unitholders. Regency manages this commodity price exposure through an integrated strategy that includes management of its contract portfolio, matching sales prices of commodities with purchases, optimization of its portfolio by monitoring basis and other price differentials in operating areas, and the use of derivative contracts. In some cases, Regency may not be able to match pricing terms or to cover its risk to price exposure with financial hedges, and it may be exposed to commodity price risk. Speculative positions are prohibited under Regency's policy.

Regency is exposed to market risks associated with commodity prices, counterparty credit, and interest rates. Regency's management and the board of directors of Regency GP have established comprehensive risk management policies and procedures to monitor and manage these market risks. Regency GP is responsible for delegation of transaction authority levels, and the Risk Management Committee of Regency GP is responsible for the overall management of credit risk and commodity price risk, including monitoring exposure limits. Regency GP's Risk Management Committee receives regular briefings on positions and exposures, credit exposures, and overall risk management in the context of market activities.

Regency's Preferred Units (see Note 7) contain embedded derivatives which are required to be bifurcated and accounted for separately, such as the holders' conversion option and Regency's call option. These embedded derivatives are accounted for using mark-to-market accounting. Regency does not expect the embedded derivatives to affect its cash flows.

The following table details Regency's outstanding commodity-related derivatives:

	December 31, 2013		December 31, 2012	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark-to-Market Derivatives				
(Non-Trading)				
Natural Gas (MMBtu) — Fixed Swaps/Futures	24,455,000	2014-2015	8,395,000	2013-2014
Propane (Gallons) — Forwards/Swaps	52,122,000	2014-2015	3,318,000	2013
NGLs (Barrels) — Forwards/Swaps	438,000	2014	243,000	2013-2014
WTI Crude Oil (Barrels) — Forwards/Swaps	521,000	2014	356,000	2014

As of December 31, 2013, Regency has less than $1 million in net hedging gains in AOCI, all of which will be amortized to earnings over the next 3 months.

Interest Rate Risk

We are exposed to market risk for changes in interest rates. In order to maintain a cost effective capital structure, we borrow funds using a mix of fixed rate debt and variable rate debt. We manage our current interest rate exposures by utilizing interest rate swaps to achieve a desired mix of fixed and variable rate debt. We also utilize forward starting interest rate swaps to lock in the rate on a portion of anticipated debt issuances.

The following is a summary of interest rate swaps outstanding as of December 31, 2013, none of which are designated as hedges for accounting purposes:

			Notional Amount Outstanding	
Entity	Term	Type[1]	December 31, 2013	December 31, 2012
ETE	March 2017	Pay a fixed rate of 1.25% and receive a floating rate	$ —	$ 500
ETP	July 2013[2]	Forward starting to pay a fixed rate of 4.03% and receive a floating rate	—	400
ETP	July 2014[2]	Forward starting to pay a fixed rate of 4.25% and receive a floating rate	400	400
ETP	July 2018	Pay a floating rate plus a spread of 4.17% and receive a fixed rate of 6.70%	600	600
ETP	June 2021	Pay a floating rate plus a spread of 2.17% and receive a fixed rate of 4.65%	400	—
ETP	February 2023	Pay a floating rate plus a spread of 1.32% and receive a fixed rate of 3.60%	400	—
Southern Union[3]	November 2016	Pay a fixed rate of 2.97% and receive a floating rate	—	75
Southern Union[3]	November 2021	Pay a fixed rate of 3.801% and receive a floating rate	275	450

(1) 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 terminate date the same as the effective date. During the year ended December 31, 2013, ETP settled $400 million of ETP's forward-starting interest rate swaps that had an effective date of July 2013.

(3) In connection with the Panhandle Merger, Southern Union's interest rate swaps outstanding were assumed by Panhandle.

Credit Risk

Credit Risk refers to the risk that a counterparty may default on its contractual obligations resulting in a loss to the Partnership. Credit policies have been approved and implemented to govern the Partnership's portfolio of counterparties with the objective of mitigating credit losses. These policies establish guidelines, controls and limits to manage credit risk within approved tolerances by mandating an appropriate evaluation of the financial condition of existing and potential counterparties, monitoring agency credit ratings, and by implementing credit practices that limit exposure according to the risk profiles of the counterparties. Furthermore, the Partnership may at times require collateral under certain circumstances to mitigate credit risk as necessary. We also implement the use of industry standard commercial agreements which allow for the netting of positive and negative exposures associated with a single commercial agreement. Additionally, we utilize master netting agreements to offset credit exposure with a single counterparty or affiliated group of counterparties.

Our counterparties consist of a diverse portfolio of customers across the energy industry, including petrochemical companies, commercial and industrials, oil and gas producers, municipalities, utilities and midstream companies. Our overall exposure may be affected positively or negatively by macroeconomic or regulatory changes that could impact our counterparties to one extent or another. Currently, management does not anticipate a material adverse effect in our financial position or results of operations as a consequence of counterparty non-performance.

ETP has maintenance margin deposits with certain counterparties in the OTC market, primarily independent system operators, and with clearing brokers. Payments on margin deposits are required when the value of a derivative exceeds its pre-established credit limit with the counterparty. Margin deposits are returned to ETP on the settlement date for non-exchange traded derivatives. ETP exchanges margin calls on a daily basis for exchange traded transactions. Since the margin calls are made daily with the exchange brokers, the fair value of the financial derivative instruments are deemed current and netted in deposits paid to vendors within other current assets in the consolidated balance sheets.

Regency is exposed to credit risk from its derivative counterparties. Regency does not require collateral from these counterparties as it deals primarily with financial institutions when entering into financial derivatives, and enters into master netting agreements that allow for netting of swap contract receivables and payables in the event of default by either party. If Regency's counterparties failed to perform under existing swap contracts, Regency's maximum loss as of December 31, 2013 would be $4 million, which would be reduced by less than $1 million, due to the netting feature.

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 sheets and recognized in net income or other comprehensive income.

Derivative Summary

The following table provides a balance sheet overview of the Partnership's derivative assets and liabilities as of December 31, 2013 and 2012:

	Fair Value of Derivative Instruments			
	Asset Derivatives		Liability Derivatives	
	December 31, 2013	December 31, 2012	December 31, 2013	December 31, 2012
Derivatives designated as hedging instruments:				
Commodity derivatives (margin deposits)	$ 3	$ 8	$ (18)	$ (10)
	3	8	(18)	(10)
Derivatives not designated as hedging instruments:				
Commodity derivatives (margin deposits)	$ 227	$ 110	$ (209)	$ (116)
Commodity derivatives	43	40	(48)	(44)
Current assets held for sale	—	1	—	—
Non-current assets held for sale	—	1	—	—
Current liabilities held for sale	—	—	—	(9)
Interest rate derivatives	47	55	(95)	(235)
Embedded derivatives in Regency Preferred Units	—	—	(19)	(25)
	317	207	(371)	(429)
Total derivatives	$ 320	$ 215	$ (389)	$ (439)

In addition to the above derivatives, $7 million of option premiums were included in price risk management liabilities as of December 31, 2012.

The following table presents the fair value of our recognized derivative assets and liabilities on a gross basis and amounts offset on the consolidated balance sheets that are subject to enforceable master netting arrangements or similar arrangements:

	Balance Sheet Location	Asset Derivatives December 31, 2013	Asset Derivatives December 31, 2012	Liability Derivatives December 31, 2013	Liability Derivatives December 31, 2012
Derivatives in offsetting agreements:					
OTC contracts	Price risk management assets (liabilities)	$ 42	$ 28	$ (38)	$ (27)
Broker cleared derivative contracts	Other current assets (liabilities)	264	149	(318)	(228)
		306	177	(356)	(255)
Offsetting agreements:					
Collateral paid to OTC counterparties	Other current assets	—	—	—	2
Counterparty netting	Price risk management assets (liabilities)	(36)	(25)	36	25
Payments on margin deposit	Other current assets	(1)	—	55	59
		(37)	(25)	91	86
Net derivatives with offsetting agreements		269	152	(265)	(169)
Derivatives without offsetting agreements		51	63	(124)	(270)
Total derivatives		$ 320	$ 215	$ (389)	$ (439)

We disclose the non-exchange traded financial derivative instruments as price risk management assets and liabilities on our consolidated balance sheets at fair value with amounts classified as either current or long-term depending on the anticipated settlement date.

The following tables summarize the amounts recognized with respect to our derivative financial instruments:

	Change in Value Recognized in OCI on Derivatives (Effective Portion) Years Ended December 31, 2013	2012	2011
Derivatives in cash flow hedging relationships:			
Commodity derivatives	$ (1)	$ 8	$ 6
Total	$ (1)	$ 8	$ 6

	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion) Years Ended December 31, 2013	2012	2011
Derivatives in cash flow hedging relationships:				
Commodity derivatives	Cost of products sold	$ 4	$ 14	$ 19
Total		$ 4	$ 14	$ 19

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain/(Loss) Recognized in Income Representing Hedge Ineffectiveness and Amount Excluded from the Assessment of Effectiveness		
		Years Ended December 31,		
		2013	2012	2011
Derivatives in fair value hedging relationships (including hedged item):				
Commodity derivatives	Cost of products sold	$ 8	$ 54	$ 34
Total		$ 8	$ 54	$ 34

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain/(Loss) Recognized in Income on Derivatives		
		Years Ended December 31,		
		2013	2012	2011
Derivatives in cash flow hedging relationships:				
Commodity derivatives – Trading	Cost of products sold	$ (11)	$ (7)	$ (30)
Commodity derivatives – Non-trading	Cost of products sold	(21)	26	9
Commodity derivatives – Non-trading	Deferred gas purchases	(3)	(26)	—
Interest rate derivatives	Gains (losses) on interest rate derivatives	53	(19)	(78)
Embedded derivatives	Other income (expense)	6	14	18
Total		$ 24	$ (12)	$ (81)

13. RETIREMENT BENEFITS:

Savings and Profit Sharing Plans

We and our subsidiaries sponsor defined contribution savings and profit sharing plans, which collectively cover virtually all employees, including those of ETP and Regency. Employer matching contributions are calculated using a formula based on employee contributions. We and our subsidiaries have made matching contributions of $47 million, $30 million and $17 million to the 401(k) savings plan for the years ended December 31, 2013, 2012 and 2011, respectively.

Pension and Other Postretirement Benefit Plans

Southern Union

Southern Union postretirement benefits expense for the year ended December 31, 2013 reflected the impact of changes Southern Union adopted as of September 30, 2013 to change its retiree medical benefits program effective January 1, 2014 which placed all retirees on a common 75% employer/25% retiree cost sharing platform, subject to caps on annual average per capita expenditures by Southern Union. Postretirement benefits expense for the year ended December 31, 2012 reflects the impact of curtailment accounting as postretirement benefits for all active participants who did not meet certain criteria were eliminated. Southern Union previously had postretirement health care and life insurance plans ("other postretirement plans") that covered substantially all employees.

In 2012, Southern Union had funded non-contributory defined benefit pension plans that covered substantially all employees of Southern Union's distribution operations. These operations were sold in 2013, see Note 3. Normal retirement age is 65, but certain plan provisions allowed for earlier retirement. Pension benefits were calculated under formulas principally based on average earnings and length of service for salaried and non-union employees and average earnings and length of service or negotiated non-wage based formulas for union employees.

Sunoco

Sunoco has both funded and unfunded noncontributory defined benefit pension plans. Sunoco also has plans which provide health care benefits for substantially all of its current retirees ("postretirement benefit plans"). The postretirement benefit plans are unfunded and the costs are shared by Sunoco and its retirees. Prior to the Sunoco Merger on October 5, 2012, pension benefits under Sunoco's defined benefit plans were frozen for most of the participants in these plans at which time Sunoco instituted a discretionary profit-sharing contribution on behalf of these employees in its defined contribution plan. Postretirement medical benefits were also phased down or eliminated for all employees retiring after July 1, 2010. Sunoco has established a trust for its postretirement benefit liabilities by making a tax-deductible contribution of approximately $200 million and restructuring the retiree medical plan to eliminate Sunoco's liability beyond this funded amount. The retiree medical plan change eliminated substantially all of Sunoco's future exposure to variances between actual results and assumptions used to estimate retiree medical plan obligations.

Obligations and Funded Status

Pension and other postretirement benefit liabilities are accrued on an actuarial basis during the years an employee provides services. The following table contains information at the dates indicated about the obligations and funded status of pension and other postretirement plans on a combined basis:

	December 31, 2013			December 31, 2012	
	Pension Benefits				
	Funded Plans	Unfunded Plans	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Change in benefit obligation:					
Benefit obligation at beginning of period	$ 1,117	$ 78	$ 296	$ 1,257	$ 359
Service cost	3	—	—	3	1
Interest cost	33	2	6	15	3
Amendments	—	—	2	—	17
Benefits paid, net	(99)	(16)	(26)	(71)	(8)
Curtailments	—	—	—	—	(80)
Actuarial (gain) loss and other	(74)	(3)	(14)	(9)	4
Settlements	(95)	—	—	—	—
Dispositions	(253)	—	(41)	—	—
Benefit obligation at end of period	$ 632	$ 61	$ 223	$ 1,195	$ 296
Change in plan assets:					
Fair value of plan assets at beginning of period	906	—	312	941	306
Return on plan assets and other	43	—	17	22	5
Employer contributions	—	—	8	14	9
Benefits paid, net	(99)	—	(26)	(71)	(8)
Settlements	(95)	—	—	—	—
Dispositions	(155)	—	(27)	—	—
Fair value of plan assets at end of period	$ 600	$ —	$ 284	$ 906	$ 312
Amount underfunded (overfunded) at end of period	$ 32	$ 61	$ (61)	$ 289	$ (16)
Amounts recognized in the consolidated balance sheets consist of:					
Non-current assets	$ —	$ —	$ 86	$ —	$ 59
Current liabilities	—	(9)	(2)	(15)	(2)
Non-current liabilities	(32)	(52)	(23)	(274)	(41)
	$ (32)	$ (61)	$ 61	$ (289)	$ 16
Amounts recognized in accumulated other comprehensive loss (pre-tax basis) consist of:					
Net actuarial gain	$ (86)	$ (4)	$ (25)	$ (1)	$ (1)
Prior service cost	—	—	18	—	16
	$ (86)	$ (4)	$ (7)	$ (1)	$ 15

The following table summarizes information at the dates indicated for plans with an accumulated benefit obligation in excess of plan assets:

	December 31, 2013			December 31, 2012	
	Pension Benefits				
	Funded Plans	Unfunded Plans	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Projected benefit obligation	$ 632	$ 61	N/A	$ 1,195	N/A
Accumulated benefit obligation	632	61	223	1,179	$ 225
Fair value of plan assets	600	—	284	906	185

Components of Net Periodic Benefit Cost

	December 31, 2013		December 31, 2012	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Net Periodic Benefit Cost:				
Service cost	$ 3	$ —	$ 3	$ 1
Interest cost	35	6	15	3
Expected return on plan assets	(54)	(9)	(21)	(5)
Prior service cost amortization	—	1	—	—
Actuarial loss amortization	2	—	—	—
Special termination benefits charge	—	—	2	—
Curtailment recognition (1)	—	—	—	(15)
Settlements	(2)	—	—	—
	(16)	(2)	(1)	(16)
Regulatory adjustment (2)	5	—	9	2
Net periodic benefit cost	$ (11)	$ (2)	$ 8	$ (14)

(1) Subsequent to the Southern Union Merger, Southern Union amended certain of its other postretirement employee benefit plans, which prospectively restrict participation in the plans for the impacted active employees. The plan amendments resulted in the plans becoming currently over-funded and, accordingly, Southern Union recorded a pre-tax curtailment gain of $75 million. Such gain was offset by establishment of a non-current refund liability in the amount of $60 million. As such, the net curtailment gain recognition was $15 million.

(2) Southern Union has historically recovered certain qualified pension benefit plan and other postretirement benefit plan costs through rates charged to utility customers in its distribution operation. Certain utility commissions require that the recovery of these costs be based on the Employee Retirement Income Security Act of 1974, as amended, or other utility commission specific guidelines. The difference between these regulatory-based amounts and the periodic benefit cost calculated pursuant to GAAP is deferred as a regulatory asset or liability and amortized to expense over periods in which this difference will be recovered in rates, as promulgated by the applicable utility commission.

Assumptions

The weighted-average assumptions used in determining benefit obligations at the dates indicated are shown in the table below:

	December 31, 2013		December 31, 2012	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Discount rate	4.65%	2.33%	3.41%	2.39%
Rate of compensation increase	N/A	N/A	3.17%	N/A

The weighted-average assumptions used in determining net periodic benefit cost for the periods presented are shown in the table below:

	December 31, 2013		December 31, 2012	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Discount rate	3.50%	2.68%	2.37%	2.43%
Expected return on assets:				
Tax exempt accounts	7.50%	6.95%	7.63%	7.00%
Taxable accounts	N/A	4.42%	N/A	4.50%
Rate of compensation increase	N/A	N/A	3.02%	N/A

The long-term expected rate of return on plan assets was estimated based on a variety of factors including the historical investment return achieved over a long-term period, the targeted allocation of plan assets and expectations concerning future returns in the marketplace for both equity and fixed income securities. Current market factors such as inflation and interest rates are evaluated before long-term market assumptions are determined. Peer data and historical returns are reviewed to ensure reasonableness and appropriateness.

The assumed health care cost trend rates used to measure the expected cost of benefits covered by Southern Union's and Sunoco's other postretirement benefit plans are shown in the table below:

	December 31,	
	2013	2012
Health care cost trend rate assumed for next year	7.57%	7.78%
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	5.42%	5.32%
Year that the rate reaches the ultimate trend rate	2018	2018

Changes in the health care cost trend rate assumptions are not expected to have a significant impact on postretirement benefits.

Plan Assets

For the Southern Union plans, the overall investment strategy is to maintain an appropriate balance of actively managed investments with the objective of optimizing longer-term returns while maintaining a high standard of portfolio quality and achieving proper diversification. To achieve diversity within its pension plan asset portfolio, Southern Union has targeted the following asset allocations: equity of 25% to 70%, fixed income of 15% to 35%, alternative assets of 10% to 35% and cash of 0% to 10%. To achieve diversity within its other postretirement plan asset portfolio, Southern Union has targeted the following asset allocations: equity of 25% to 35%, fixed income of 65% to 75% and cash and cash equivalents of 0% to 10%.

The investment strategy of Sunoco funded defined benefit plans is to achieve consistent positive returns, after adjusting for inflation, and to maximize long-term total return within prudent levels of risk through a combination of income and capital appreciation. The objective of this strategy is to reduce the volatility of investment returns, maintain a sufficient funded status of the plans and limit required contributions. Sunoco has targeted the following asset allocations: equity of 35%, fixed income of 55%, and private equity investments of 10%. Sunoco anticipates future shifts in targeted asset allocations from equity securities to fixed income securities if funding levels improve due to asset performance or Sunoco contributions.

The fair value of the pension plan assets by asset category at the dates indicated is as follows:

	Fair Value as of December 31, 2013	Fair Value Measurements at December 31, 2013 Using Fair Value Hierarchy		
		Level 1	Level 2	Level 3
Asset Category:				
Cash and cash equivalents	$ 12	$ 12	$ —	$ —
Mutual funds [(1)]	368	—	281	87
Fixed income securities	220	—	220	—
Total	$ 600	$ 12	$ 501	$ 87

(1) Primarily comprised of approximately 66% equities, 10% fixed income securities, and 24% in other investments as of December 31, 2013.

	Fair Value as of December 31, 2012	Fair Value Measurements at December 31, 2012 Using Fair Value Hierarchy		
		Level 1	Level 2	Level 3
Asset Category:				
Cash and cash equivalents	$ 25	$ 25	$ —	$ —
Mutual funds [(1)]	516	—	433	83
Fixed income securities	354	—	354	—
Multi-strategy hedge funds [(2)]	11	—	11	—
Total	$ 906	$ 25	$ 798	$ 83

(1) Primarily comprised of approximately 36% equities, 54% fixed income securities, and 10% in other investments as of December 31, 2012.

(2) Primarily includes hedge funds that invest in multiple strategies, including relative value, opportunistic/macro, long/short equities, merger arbitrage/event driven, credit, and short selling strategies, to generate long-term capital appreciation through a portfolio having a diversified risk profile with relatively low volatility and a low correlation with traditional equity and fixed-income markets. These investments can generally be redeemed effective as of the last day of a calendar quarter at the net asset value per share of the investment with approximately 65 days prior written notice.

The fair value of the other postretirement plan assets by asset category at the dates indicated is as follows:

	Fair Value as of December 31, 2013	Fair Value Measurements at December 31, 2013 Using Fair Value Hierarchy		
		Level 1	Level 2	Level 3
Asset Category:				
Cash and Cash Equivalents	$ 10	$ 10	$ —	$ —
Mutual funds [(1)]	130	112	18	—
Fixed income securities	144	—	144	—
Total	$ 284	$ 122	$ 162	$ —

(1) Primarily comprised of approximately 41% equities, 48% fixed income securities, 6% cash, and 5% in other investments as of December 31, 2013.

The Level 1 plan assets are valued based on active market quotes. The Level 2 plan assets are valued based on the net asset value per share (or its equivalent) of the investments, which was not determinable through publicly published sources but was calculated consistent with authoritative accounting guidelines. See Note 2 for information related to the framework used to measure the fair value of its pension and other postretirement plan assets.

	Fair Value as of December 31, 2012	Fair Value Measurements at December 31, 2012 Using Fair Value Hierarchy		
		Level 1	Level 2	Level 3
Asset Category:				
Cash and Cash Equivalents	$ 7	$ 7	$ —	$ —
Mutual funds [(1)]	147	126	21	—
Fixed income securities	158	—	158	—
Total	$ 312	$ 133	$ 179	$ —

(1) Primarily comprised of approximately 19% equities, 74% fixed income securities, 4% cash, and 3% in other investments as of December 31, 2012.

The Level 1 plan assets are valued based on active market quotes. The Level 2 plan assets are valued based on the net asset value per share (or its equivalent) of the investments, which was not determinable through publicly published sources but was calculated consistent with authoritative accounting guidelines. See Note 2 for information related to the framework used to measure the fair value of its pension and other postretirement plan assets.

Contributions

We expect to contribute approximately $23 million to pension plans and approximately $18 million to other postretirement plans in 2014. The cost of the plans are funded in accordance with federal regulations, not to exceed the amounts deductible for income tax purposes.

Benefit Payments

Southern Union's and Sunoco's estimate of expected benefit payments, which reflect expected future service, as appropriate, in each of the next five years and in the aggregate for the five years thereafter are shown in the table below:

	Pension Benefits		
Years	Funded Plans	Unfunded Plans	Other Postretirement Benefits (Gross, Before Medicare Part D)
2014	$ 82	$ 9	$ 31
2015	77	9	29
2016	67	8	28
2017	61	7	26
2018	56	7	24
2019 – 2023	220	23	87

The Medicare Prescription Drug Act provides for a prescription drug benefit under Medicare ("Medicare Part D") as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a prescription drug benefit that is at least actuarially equivalent to Medicare Part D.

Southern Union does not expect to receive any Medicare Part D subsidies in any future periods.

14. RELATED PARTY TRANSACTIONS:

The Parent Company has agreements with subsidiaries to provide or receive various general and administrative services. The Parent Company pays ETP to provide services on its behalf and the behalf of other subsidiaries of the Parent Company. The Parent Company receives management fees from certain of its subsidiaries, which include the reimbursement of various general and administrative services for expenses incurred by ETP on behalf of those subsidiaries. All such amounts have been eliminated in our consolidated financial statements.

In the ordinary course of business, our subsidiaries have related party transactions between each other which are generally based on transactions made at market-related rates. Our consolidated revenues and expenses reflect the elimination of all material intercompany transactions (see Note 15).

In addition, subsidiaries of ETE recorded sales with affiliates of $1.44 billion, $189 million and $1.05 billion during the years ended December 31, 2013, 2012 and 2011, respectively.

15. REPORTABLE SEGMENTS:

As a result of the Holdco Acquisition in April 2013, our reportable segments were re-evaluated and currently reflect the following reportable segments, which conduct their business exclusively in the United States of America, as follows:

- Investment in ETP, including the consolidated operations of ETP;
- Investment in Regency, including the consolidated operations of Regency; and
- Corporate and Other, including the following:
  - activities of the Parent Company; and
  - the goodwill and property, plant and equipment fair value adjustments recorded as a result of the 2004 reverse acquisition of Heritage Propane Partners, L.P.

Related party transactions among our segments are generally based on transactions made at market-related rates. Consolidated revenues and expenses reflect the elimination of all material intercompany transactions.

We previously reported net income as a measure of segment performance. Due to the change in our reportable segments described above, the financial information available to our chief operating decision maker to assess the performance is now based on Segment Adjusted EBITDA. Therefore, we have accordingly revised our segment operating performance measure that we report. 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). Segment 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. Based on the change in our segment performance measure, we have recast the presentation of our segment results for the prior years to be consistent with the current year presentation.

As discussed in Note 3, Regency completed its acquisition of SUGS on April 30, 2013. Therefore, the investment in Regency segment amounts have been retrospectively adjusted to reflect SUGS beginning March 26, 2012.

Eliminations in the tables below include the following:

- ETP's Segment Adjusted EBITDA reflects 100% of Lone Star, which is a consolidated subsidiary of ETP. Regency's Segment Adjusted EBITDA includes its 30% investment in Lone Star. Therefore, 30% of the results of Lone Star are included in eliminations.
- ETP's Segment Adjusted EBITDA reflects the results of SUGS from March 26, 2012 to April 30, 2013. Because the SUGS Contribution was a transaction between entities under common control, Regency's results have been recast to retrospectively consolidate SUGS beginning March 26, 2012. Therefore, the eliminations also include the results of SUGS from March 26, 2012 to April 30, 2013.

	Years Ended December 31,		
	2013	2012	2011
Revenues:			
Investment in ETP:			
Revenues from external customers	$ 46,210	$ 15,671	$ 6,761
Intersegment revenues	129	31	38
	46,339	15,702	6,799
Investment in Regency:			
Revenues from external customers	2,404	1,986	1,426
Intersegment revenues	117	14	8
	2,521	2,000	1,434
Adjustments and Eliminations:	(525)	(738)	(43)
Total revenues	$ 48,335	$ 16,964	$ 8,190
Costs of products sold:			
Investment in ETP	$ 41,204	$ 12,266	$ 4,175
Investment in Regency	1,793	1,387	1,013
Adjustments and Eliminations	(443)	(565)	(19)
Total costs of products sold	$ 42,554	$ 13,088	$ 5,169
Depreciation and amortization:			
Investment in ETP	1,032	656	405
Investment in Regency	287	252	169
Corporate and Other	16	14	12
Adjustments and Eliminations	(22)	(51)	—
Total depreciation and amortization	$ 1,313	$ 871	$ 586

	Years Ended December 31,		
	2013	2012	2011
Equity in earnings of unconsolidated affiliates:			
Investment in ETP	$ 172	$ 142	$ 26
Investment in Regency	135	105	120
Adjustments and Eliminations	(71)	(35)	(29)
Total equity in earnings of unconsolidated affiliates	$ 236	$ 212	$ 117

	Years Ended December 31,		
	2013	2012	2011
Segment Adjusted EBITDA:			
Investment in ETP	$ 3,953	$ 2,744	$ 1,781
Investment in Regency	608	517	420
Corporate and Other	(43)	(52)	(29)
Adjustments and Eliminations	(151)	(104)	(41)
Total Segment Adjusted EBITDA	4,367	3,105	2,131
Depreciation and amortization	(1,313)	(871)	(586)
Interest expense, net of interest capitalized	(1,221)	(1,018)	(740)
Bridge loan related fees	—	(62)	—
Gain on deconsolidation of Propane Business	—	1,057	—
Gain on sale of AmeriGas common units	87	—	—
Goodwill impairment	(689)	—	—
Gains (losses) on interest rate derivatives	53	(19)	(78)
Non-cash unit-based compensation expense	(61)	(47)	(42)
Unrealized gains on commodity risk management activities	48	10	7
Losses on extinguishments of debt	(162)	(123)	—
LIFO valuation adjustments	3	(75)	—
Adjusted EBITDA related to discontinued operations	(76)	(99)	(23)
Adjusted EBITDA related to unconsolidated affiliates	(727)	(647)	(231)
Equity in earnings of unconsolidated affiliates	236	212	117
Non-operating environmental remediation	(168)	—	—
Other, net	(2)	14	(7)
Income from continuing operations before income tax expense	$ 375	$ 1,437	$ 548

	December 31,		
	2013	2012	2011
Total assets:			
Investment in ETP	$ 43,702	$ 43,230	$ 15,519
Investment in Regency	8,782	8,123	5,568
Corporate and Other	720	707	470
Adjustments and Eliminations	(2,874)	(3,156)	(660)
Total	$ 50,330	$ 48,904	$ 20,897

	Years Ended December 31,		
	2013	2012	2011
Additions to property, plant and equipment, net of contributions in aid of construction costs (accrual basis):			
Investment in ETP	$ 2,455	$ 3,049	$ 1,484
Investment in Regency	1,034	560	406
Adjustments and Eliminations	—	(124)	—
Total	$ 3,489	$ 3,485	$ 1,890

	December 31,		
	2013	2012	2011
Advances to and investments in affiliates:			
Investment in ETP	$ 4,436	$ 3,502	$ 201
Investment in Regency	2,097	2,214	1,925
Adjustments and Eliminations	(2,519)	(979)	(629)
Total	$ 4,014	$ 4,737	$ 1,497

The following tables provide revenues, grouped by similar products and services, for our reportable segments. These amounts include intersegment revenues for transactions between ETP and Regency.

Investment in ETP

	Years Ended December 31,		
	2013	2012	2011
Intrastate Transportation and Storage	$ 2,250	$ 2,012	$ 2,398
Interstate Transportation and Storage	1,270	1,109	447
Midstream	1,307	1,757	1,082
NGL Transportation and Services	2,063	619	363
Investment in Sunoco Logistics	16,480	3,109	—
Retail Marketing	21,004	5,926	—
All Other	1,965	1,170	2,509
Total revenues	46,339	15,702	6,799
Less: Intersegment revenues	129	31	38
Revenues from external customers	$ 46,210	$ 15,671	$ 6,761

Investment in Regency

	Years Ended December 31,		
	2013	2012	2011
Gathering and Processing	$ 2,287	$ 1,797	$ 1,226
Natural Gas Transportation	1	1	1
Contract Services	215	183	190
Corporate and others	18	19	17
Total revenues	2,521	2,000	1,434
Less: Intersegment revenues	117	14	8
Revenues from external customers	$ 2,404	$ 1,986	$ 1,426

16. QUARTERLY FINANCIAL DATA (UNAUDITED):

Summarized unaudited quarterly financial data is presented below. Earnings per unit are computed on a stand-alone basis for each quarter and total year. ETP's ETC OLP business is seasonal due to the operations of ET Fuel System and the HPL System. We expect margin related to the HPL System operations to be higher during the periods from November through March of each year and lower during the periods from April through October of each year due to the increased demand for natural gas during the cold weather. However, 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.

	Quarters Ended				
	March 31	June 30	September 30	December 31	Total Year
2013:					
Revenues	$ 11,179	$ 12,063	$ 12,486	$ 12,607	$ 48,335
Gross margin	1,372	1,498	1,422	1,489	5,781
Operating income (loss)	531	644	529	(153)	1,551
Net income (loss)	322	338	356	(701)	315
Limited Partners' interest in net income (loss)	90	127	150	(171)	196
Basic net income (loss) per limited partner unit	$ 0.16	$ 0.23	$ 0.27	$ (0.31)	$ 0.35
Diluted net income (loss) per limited partner unit	$ 0.16	$ 0.23	$ 0.27	$ (0.31)	$ 0.35

The three months ended December 31, 2013 was impacted by ETP's recognition of a goodwill impairment of $689 million.

	Quarters Ended				
	March 31	June 30	September 30	December 31	Total Year
2012:					
Revenues	$ 1,669	$ 1,875	$ 2,107	$ 11,313	$ 16,964
Gross margin	654	916	876	1,430	3,876
Operating income	183	367	358	452	1,360
Net income (loss)	961	75	(34)	272	1,274
Limited Partners' interest in net income	166	53	35	48	302
Basic net income per limited partner unit	$ 0.37	$ 0.10	$ 0.06	$ 0.09	$ 0.57
Diluted net income per limited partner unit	$ 0.36	$ 0.10	$ 0.06	$ 0.09	$ 0.57

17. SUPPLEMENTAL FINANCIAL STATEMENT INFORMATION:

Following are the financial statements of the Parent Company, which are included to provide additional information with respect to the Parent Company's financial position, results of operations and cash flows on a stand-alone basis:

BALANCE SHEETS

	December 31, 2013	December 31, 2012
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 8	$ 9
Accounts receivable from related companies	5	11
Other current assets	—	3
Total current assets	13	23
ADVANCES TO AND INVESTMENTS IN AFFILIATES	3,841	6,094
INTANGIBLE ASSETS, net	14	19
NOTE RECEIVABLE FROM AFFILIATE	—	166
GOODWILL	9	9
OTHER NON-CURRENT ASSETS, net	41	56
Total assets	$ 3,918	$ 6,367
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES:		
Accounts payable	$ —	$ 1
Accounts payable to related companies	11	15
Interest payable	24	48
Price risk management liabilities	—	5
Accrued and other current liabilities	3	1
Current maturities of long-term debt	—	4
Total current liabilities	38	74
LONG-TERM DEBT, less current maturities	2,801	3,840
PREFERRED UNITS	—	331
OTHER NON-CURRENT LIABILITIES	1	9
COMMITMENTS AND CONTINGENCIES		
PARTNERS' CAPITAL:		
General Partner	(3)	—
Limited Partners – Common Unitholders (559,923,300 and 559,911,216 units authorized, issued and outstanding at December 31, 2013 and 2012, respectively)	1,066	2,125
Class D Units (1,540,000 units authorized, issued and outstanding at December 31, 2013)	6	—
Accumulated other comprehensive income (loss)	9	(12)
Total partners' capital	1,078	2,113
Total liabilities and partners' capital	$ 3,918	$ 6,367

STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2013	2012	2011
SELLING, GENERAL AND ADMINISTRATIVE EXPENSES	$ (56)	$ (53)	$ (30)
OTHER INCOME (EXPENSE):			
Interest expense, net of interest capitalized	(210)	(235)	(164)
Bridge loan related fees	—	(62)	—
Equity in earnings of unconsolidated affiliates	617	666	509
Gains (losses) on interest rate derivatives	9	(15)	—
Loss on extinguishment of debt	(157)	—	—
Other, net	(8)	(4)	(5)
INCOME BEFORE INCOME TAXES	195	297	310
Income tax benefit	(1)	(7)	—
NET INCOME	196	304	310
GENERAL PARTNER’S INTEREST IN NET INCOME	—	2	1
LIMITED PARTNERS’ INTEREST IN NET INCOME	$ 196	$ 302	$ 309

STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2013	2012	2011
NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES	$ 768	$ 555	$ 469
CASH FLOWS FROM INVESTING ACTIVITIES:			
Cash paid for acquisitions	—	(1,113)	—
Proceeds from Holdco Transaction	1,332	—	—
Contributions to affiliates	(8)	(487)	—
Note receivable from affiliate	—	(221)	—
Payments received on note receivable from affiliate	166	55	—
Net cash provided by (used in) investing activities	1,490	(1,766)	—
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from borrowings	2,080	2,108	92
Principal payments on debt	(3,235)	(162)	(20)
Distributions to partners	(733)	(666)	(526)
Redemption of Preferred Units	(340)	—	—
Debt issuance costs	(31)	(78)	(24)
Net cash provided by (used in) financing activities	(2,259)	1,202	(478)
DECREASE IN CASH AND CASH EQUIVALENTS	(1)	(9)	(9)
CASH AND CASH EQUIVALENTS, beginning of period	9	18	27
CASH AND CASH EQUIVALENTS, end of period	$ 8	$ 9	$ 18

ENERGY TRANSFER EQUITY, L.P. AND SUBSIDIARIES

INDEX TO FINANCIAL STATEMENTS OF CERTAIN SUBSIDIARIES INCLUDED PURSUANT TO RULE 3-16 OF REGULATION S-X

1. ETE COMMON HOLDINGS, LLC FINANCIAL STATEMENTS

INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Members
ETE Common Holdings, LLC

We have audited the accompanying balance sheet of ETE Common Holdings, LLC (a Delaware limited liability company) (the “Company”) as of December 31, 2013, and the related statements of comprehensive income, members’ equity, and cash flows for the period from April 26, 2013 (inception) to December 31, 2013. These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Company’s internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company’s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of ETE Common Holdings, LLC as of December 31, 2013, and the results of its operations and its cash flows for the period from April 26, 2013 (inception) to December 31, 2013 in conformity with accounting principles generally accepted in the United States of America.

/s/ GRANT THORNTON LLP

Dallas, Texas
February 27, 2014

ETE COMMON HOLDINGS, LLC

BALANCE SHEET
(Dollars in millions)

		December 31, 2013
ASSETS		
AFFILIATE RECEIVABLE	$	151
ADVANCES TO AND INVESTMENTS IN UNCONSOLIDATED AFFILIATES		1,662
Total assets	$	1,813
LIABILITIES AND EQUITY		
AFFILIATE PAYABLE	$	111
MEMBERS’ EQUITY:		
Members’ capital	$	1,700
Accumulated other comprehensive income		2
Total members’ equity		1,702
Total liabilities and members’ equity	$	1,813

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

ETE COMMON HOLDINGS, LLC

STATEMENT OF COMPREHENSIVE INCOME
(Dollars in millions)

	Period from April 26, 2013 (inception) to December 31, 2013
Equity in earnings of unconsolidated affiliates	$ 134
INCOME BEFORE INCOME TAX EXPENSE	134
Income tax expense	—
NET INCOME	$ 134
Other comprehensive income, net of tax	$ 2
COMPREHENSIVE INCOME	$ 136

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

ETE COMMON HOLDINGS, LLC

CONSOLIDATED STATEMENT OF MEMBERS' EQUITY
(Dollars in millions)

	ETE Common Holdings Member, LLC	Energy Transfer Equity, L.P.	Total Members' Equity
Balance, April 26, 2013 (Inception)	$ —	$ —	$ —
Contributions from members	3	1,669	1,672
Distributions to members	—	(106)	(106)
Net income	—	134	134
Other comprehensive income	—	2	2
Balance, December 31, 2013	$ 3	$ 1,699	$ 1,702

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

ETE COMMON HOLDINGS, LLC

STATEMENT OF CASH FLOWS
(Dollars in millions)

		Period from April 26, 2013 (Inception) to December 31, 2013
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$	134
Reconciliation of net income to net cash provided by operating activities:		
Equity in earnings of unconsolidated affiliates		(134)
Net change in operating assets and liabilities		(5)
Net cash used in operating activities		(5)
Net cash provided by investing activities		—
CASH FLOWS FROM FINANCING ACTIVITIES:		
Contributions from members		5
Net cash provided by financing activities		5
INCREASE IN CASH AND CASH EQUIVALENTS		—
CASH AND CASH EQUIVALENTS, beginning of period		—
CASH AND CASH EQUIVALENTS, end of period	$	—

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

ETE COMMON HOLDINGS, LLC

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Tabular dollar amounts in millions)

1. OPERATIONS AND ORGANIZATION:

Business Operations

ETE Common Holdings, LLC (the “Company,” “we,” or “ETE Holdings”) was formed on April 26, 2013 and is a subsidiary of Energy Transfer Equity, L.P. (“ETE”). In connection with ETE’s April 30, 2013 sale of its remaining 60% interest in ETP Holdco Corporation (“Holdco”) to Energy Transfer Partners, L.P. (“ETP”), the Company received 55.4 ETP limited partner common units and 0.1% of Sunoco Partners LLC, the general partner of Sunoco Logistics L.P. (“Sunoco Partners”).

On October 31, 2013, the Company completed an exchange of 50.2 million ETP limited partner common units for 50.2 million ETP Class H units. The ETP Class H units are generally entitled to (i) allocations of profits, losses and other items from ETP corresponding to 50.05% of the profits, losses, and other items allocated to ETP by Sunoco Partners LLC (“Sunoco Partners”), the general partner of Sunoco Logistics Partners L.P. (“Sunoco Logistics”), with respect to the IDRs and general partner interest in Sunoco Logistics held by Sunoco Partners, (ii) distributions from available cash at ETP for each quarter equal to 50.05% of the cash distributed to ETP by Sunoco Partners with respect to the IDRs and general partner interest in Sunoco Logistics held by Sunoco Partners for such quarter and, to the extent not previously distributed to holders of the Class H Units, for any previous quarters and (iii) incremental additional cash distributions in the aggregate amount of $329 million, to be payable by ETP to ETE Holdings over 15 quarters, commencing with the quarter ended September 30, 2013 and ending with the quarter ending March 31, 2017.

The Company currently owns 50.2 million ETP Class H Units and 5.2 million ETP limited partner common units.

The Company conducts no operations independent of its equity ownership interest in ETP. Its principal sources of cash flow are derived from its investments in the limited partner interest in ETP and it has no cash requirements. ETP is a master limited partnership owning and operating one of the largest and most diversified portfolios of energy assets in the United States. ETP currently owns and operates approximately 35,000 miles of natural gas and natural gas liquids pipelines. ETP owns 100% of Panhandle Eastern Pipe Line Company, LP (the successor of Southern Union Company) and Sunoco, Inc., and a 70% interest in Lone Star NGL LLC, a joint venture that owns and operates natural gas liquids storage, fractionation and transportation assets. ETP also owns the general partner, 100% of the incentive distribution rights, and approximately 33.5 million common units in Sunoco Logistics, which operates a geographically diverse portfolio of crude oil and refined products pipelines, terminalling and crude oil acquisition and marketing assets.

Financial Statement Presentation

The financial statements of the Company presented herein for the period from April 26, 2013 to December 31, 2013, have been prepared in accordance with GAAP. As the Company was formed on April 26, 2013, the financial statements herein do not include comparative periods.

2. ADVANCES TO AND INVESTMENTS IN UNCONSOLIDATED AFFILIATE:

The Company owns 50.2 million ETP Class H Units and 5.2 million ETP limited partner common units which are accounted for under the equity method and 0.1% of Sunoco Partners.

We record changes in our ownership interest of ETP’s equity transactions, with gain or loss recognized in equity in earnings of unconsolidated affiliates. For example, upon ETP’s issuance of common units in a public offering, we record any difference between the amount of consideration received or paid and the amount by which the investment in unconsolidated affiliate is adjusted. If ETP issues units at a price less than our carrying value per unit, we assess whether the investment has been impaired, in which case a provision would be reflected in our statement of comprehensive income. For the period from April 30, 2013 to December 31, 2013, no impairments were recorded and we recorded gains of $38.1 million in earnings from unconsolidated affiliates related to ETP’s unit issuances.

Summarized Financial Information

The following tables present selected balance sheet and income statement data for our unconsolidated affiliate, ETP (on a 100% basis for all periods presented).

	December 31, 2013
Current assets	$ 6,239
Property, plant and equipment, net	25,947
Advances to and investments in unconsolidated affiliates	4,436
Goodwill	4,729
Intangible assets, net	1,568
Other non-current assets, net	783
Total assets	$ 43,702
Current liabilities	$ 6,067
Long-term debt, less current maturities	16,451
Deferred income taxes	3,762
Other non-current liabilities	1,134
Equity	16,288
Total liabilities and equity	$ 43,702

	Year Ended December 31, 2013
Revenue	$ 46,339
Operating income	1,541
Net income	768

3. <u>SUBSEQUENT EVENTS</u>:

Subsequent events have been evaluated through February 27, 2014, the date the financial statements were available to be issued.

2. ENERGY TRANSFER PARTNERS, L.P. FINANCIAL STATEMENTS

INDEX TO FINANCIAL STATEMENTS

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, 2013 and 2012, 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, 2013. 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. as of December 31, 2012 and for the period from October 5, 2012 to December 31, 2012, 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, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 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, 2013, based on criteria established in the 1992 Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 27, 2014 (not separately included herein) expressed an unqualified opinion thereon.

/s/ GRANT THORNTON LLP

Dallas, Texas
February 27, 2014

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

	December 31, 2013	December 31, 2012
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 549	$ 311
Accounts receivable, net	3,359	2,910
Accounts receivable from related companies	165	94
Inventories	1,765	1,495
Exchanges receivable	56	55
Price risk management assets	35	21
Current assets held for sale	—	184
Other current assets	310	334
Total current assets	6,239	5,404
PROPERTY, PLANT AND EQUIPMENT	28,430	27,412
ACCUMULATED DEPRECIATION	(2,483)	(1,639)
	25,947	25,773
NON-CURRENT ASSETS HELD FOR SALE	—	985
ADVANCES TO AND INVESTMENTS IN UNCONSOLIDATED AFFILIATES	4,436	3,502
NON-CURRENT PRICE RISK MANAGEMENT ASSETS	17	42
GOODWILL	4,729	5,606
INTANGIBLE ASSETS, net	1,568	1,561
OTHER NON-CURRENT ASSETS, net	766	357
Total assets	$ 43,702	$ 43,230

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

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

	December 31, 2013	December 31, 2012
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 3,627	$ 3,002
Accounts payable to related companies	45	24
Exchanges payable	285	156
Price risk management liabilities	45	110
Accrued and other current liabilities	1,428	1,562
Current maturities of long-term debt	637	609
Current liabilities held for sale	—	85
Total current liabilities	6,067	5,548
NON-CURRENT LIABILITIES HELD FOR SALE	—	142
LONG-TERM DEBT, less current maturities	16,451	15,442
LONG-TERM NOTES PAYABLE — RELATED PARTY	—	166
NON-CURRENT PRICE RISK MANAGEMENT LIABILITIES	54	129
DEFERRED INCOME TAXES	3,762	3,476
OTHER NON-CURRENT LIABILITIES	1,080	995
COMMITMENTS AND CONTINGENCIES (Note 10)		
EQUITY:		
General Partner	171	188
Limited Partners:		
Common Unitholders (333,826,372 and 301,485,604 units authorized, issued and outstanding as of December 31, 2013 and 2012, respectively)	9,797	9,026
Class E Unitholders (8,853,832 units authorized, issued and outstanding – held by subsidiary)	—	—
Class F Unitholders (zero and 90,706,000 units authorized, issued and outstanding as of December 31, 2013 and 2012, respectively – held by subsidiary)	—	—
Class G Unitholders (90,706,000 and zero units authorized, issued and outstanding as of December 31, 2013 and 2012, respectively – held by subsidiary)	—	—
Class H Unitholders (50,160,000 and zero units authorized, issued and outstanding as of December 31, 2013 and 2012, respectively)	1,511	—
Accumulated other comprehensive income (loss)	61	(13)
Total partners' capital	11,540	9,201
Noncontrolling interest	4,748	8,131
Total equity	16,288	17,332
Total liabilities and equity	$ 43,702	$ 43,230

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

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

	Years Ended December 31,		
	2013	2012	2011
REVENUES:			
Natural gas sales	$ 3,165	$ 2,387	$ 2,534
NGL sales	2,817	1,718	1,113
Crude sales	15,477	2,872	—
Gathering, transportation and other fees	2,590	2,007	1,488
Refined product sales	18,479	5,299	—
Other	3,811	1,419	1,664
Total revenues	46,339	15,702	6,799
COSTS AND EXPENSES:			
Cost of products sold	41,204	12,266	4,175
Operating expenses	1,388	951	799
Depreciation and amortization	1,032	656	405
Selling, general and administrative	485	435	173
Goodwill impairment	689	—	—
Total costs and expenses	44,798	14,308	5,552
OPERATING INCOME	1,541	1,394	1,247
OTHER INCOME (EXPENSE):			
Interest expense, net of interest capitalized	(849)	(665)	(474)
Equity in earnings of unconsolidated affiliates	172	142	26
Gain on deconsolidation of Propane Business	—	1,057	—
Gain on sale of AmeriGas common units	87	—	—
Loss on extinguishment of debt	—	(115)	—
Gains (losses) on interest rate derivatives	44	(4)	(77)
Non-operating environmental remediation	(168)	—	—
Other, net	5	11	(3)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE	832	1,820	719
Income tax expense from continuing operations	97	63	19
INCOME FROM CONTINUING OPERATIONS	735	1,757	700
Income (loss) from discontinued operations	33	(109)	(3)
NET INCOME	768	1,648	697
LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTEREST	312	79	28
NET INCOME ATTRIBUTABLE TO PARTNERS	456	1,569	669
GENERAL PARTNER’S INTEREST IN NET INCOME	506	461	433
CLASS H UNITHOLDER’S INTEREST IN NET INCOME	48	—	—
LIMITED PARTNERS’ INTEREST IN NET INCOME (LOSS)	$ (98)	$ 1,108	$ 236
INCOME (LOSS) FROM CONTINUING OPERATIONS PER LIMITED PARTNER UNIT:			
Basic	$ (0.23)	$ 4.93	$ 1.12
Diluted	$ (0.23)	$ 4.91	$ 1.12
NET INCOME (LOSS) PER LIMITED PARTNER UNIT:			
Basic	$ (0.18)	$ 4.43	$ 1.10
Diluted	$ (0.18)	$ 4.42	$ 1.10

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

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Dollars in millions)

	Years Ended December 31,		
	2013	2012	2011
Net income	$ 768	$ 1,648	$ 697
Other comprehensive income (loss), net of tax:			
Reclassification to earnings of gains and losses on derivative instruments accounted for as cash flow hedges	(4)	(14)	(38)
Change in value of derivative instruments accounted for as cash flow hedges	(1)	8	19
Change in value of available-for-sale securities	2	—	(1)
Actuarial gain (loss) relating to pension and other postretirement benefits	66	(10)	—
Foreign currency translation adjustment	(1)	—	—
Change in other comprehensive income from equity investments	17	(9)	—
	79	(25)	(20)
Comprehensive income	847	1,623	677
Less: Comprehensive income attributable to noncontrolling interest	312	74	28
Comprehensive income attributable to partners	$ 535	$ 1,549	$ 649

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

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF EQUITY
(Dollars in millions)

		Limited Partners				
	General Partner	Common Unitholders	Class H Units	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
Balance, December 31, 2010	$ 175	$ 4,542	$ —	$ 26	$ —	$ 4,743
Distributions to partners	(426)	(733)	—	—	—	(1,159)
Distributions to noncontrolling interest	—	—	—	—	(44)	(44)
Units issued for cash	—	1,467	—	—	—	1,467
Capital contributions from noncontrolling interest	—	—	—	—	645	645
Issuance of units in acquisitions	—	3	—	—	—	3
Other comprehensive loss, net of tax	—	—	—	(20)	—	(20)
Other, net	—	18	—	—	—	18
Net income	433	236	—	—	28	697
Balance, December 31, 2011	182	5,533	—	6	629	6,350
Distributions to partners	(454)	(889)	—	—	—	(1,343)
Distributions to noncontrolling interest	—	—	—	—	(233)	(233)
Units issued for cash	—	791	—	—	—	791
Capital contributions from noncontrolling interest	—	—	—	—	343	343
Sunoco Merger (see Note 3)	—	2,288	—	—	3,580	5,868
Holdco Transaction (see Note 3)	—	165	—	—	3,748	3,913
Issuance of units in other acquisitions (excluding Sunoco)	—	7	—	—	—	7
Other comprehensive loss net of tax	—	—	—	(19)	(6)	(25)
Other, net	(1)	23	—	—	(9)	13
Net income	461	1,108	—	—	79	1,648
Balance, December 31, 2012	188	9,026	—	(13)	8,131	17,332
Distributions to partners	(523)	(1,228)	(51)	—	—	(1,802)
Distributions to noncontrolling interest	—	—	—	—	(382)	(382)
Units issued for cash	—	1,611	—	—	—	1,611
Issuance of Class H Units (see Note 7)	—	(1,514)	1,514	—	—	—
Capital contributions from noncontrolling interest	—	—	—	—	137	137
Holdco Acquisition and SUGS Contribution (see Note 3)	—	2,013	—	(5)	(3,448)	(1,440)
Other comprehensive income, net of tax	—	—	—	79	—	79
Other, net	—	(13)	—	—	(2)	(15)
Net income (loss)	506	(98)	48	—	312	768
Balance, December 31, 2013	$ 171	$ 9,797	$ 1,511	$ 61	$ 4,748	$ 16,288

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

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Dollars in millions)

	Years Ended December 31,		
	2013	2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 768	$ 1,648	$ 697
Reconciliation of net income to net cash provided by operating activities:			
Depreciation and amortization	1,032	656	405
Deferred income taxes	48	62	4
Gain on curtailment of other postretirement benefits	—	(15)	—
Amortization included in interest expense	(80)	(35)	10
Loss on extinguishment of debt	—	115	—
LIFO valuation adjustments	(3)	75	—
Non-cash compensation expense	47	42	38
Gain on deconsolidation of Propane Business	—	(1,057)	—
Gain on sale of AmeriGas common units	(87)	—	—
Goodwill impairment	689	—	—
Write-down of assets included in loss from discontinued operations	—	132	—
Distributions on unvested awards	(12)	(8)	(8)
Equity in earnings of unconsolidated affiliates	(172)	(142)	(26)
Distributions from unconsolidated affiliates	247	132	29
Other non-cash	42	68	29
Net change in operating assets and liabilities, net of effects of acquisitions and deconsolidations (see Note 2)	(146)	(475)	166
Net cash provided by operating activities	2,373	1,198	1,344
CASH FLOWS FROM INVESTING ACTIVITIES:			
Cash paid for Citrus Merger	—	(1,895)	—
Cash proceeds from contribution and sale of propane operations	—	1,443	—
Cash proceeds from SUGS Contribution (See Note 3)	504	—	—
Cash paid for Holdco Acquisition (See Note 3)	(1,332)	—	—
Cash proceeds from the sale of the MGE and NEG assets (See Note 3)	1,008	—	—
Cash proceeds from the sale of AmeriGas common units	346	—	—
Cash (paid) received from all other acquisitions	(405)	531	(1,972)
Capital expenditures (excluding allowance for equity funds used during construction)	(2,575)	(2,840)	(1,416)
Contributions in aid of construction costs	52	35	25
Contributions to unconsolidated affiliates	(1)	(30)	(222)
Distributions from unconsolidated affiliates in excess of cumulative earnings	217	130	22
Proceeds from sale of disposal group	—	207	—
Proceeds from the sale of assets	53	18	9
Restricted cash	(348)	5	—
Other	21	111	1
Net cash used in investing activities	(2,460)	(2,285)	(3,553)

CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from borrowings	8,001	8,208	6,594
Repayments of long-term debt	(7,016)	(6,598)	(5,217)
Proceeds from borrowings from affiliates	—	221	—
Repayments of borrowings from affiliates	(166)	(55)	—
Net proceeds from issuance of Limited Partner units	1,611	791	1,467
Capital contributions received from noncontrolling interest	147	320	645
Distributions to partners	(1,802)	(1,343)	(1,159)
Distributions to noncontrolling interest	(382)	(233)	(44)
Debt issuance costs	(32)	(20)	(20)
Other	(36)	—	—
Net cash provided by financing activities	325	1,291	2,266
INCREASE IN CASH AND CASH EQUIVALENTS	238	204	57
CASH AND CASH EQUIVALENTS, beginning of period	311	107	50
CASH AND CASH EQUIVALENTS, end of period	$ 549	$ 311	$ 107

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

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Tabular dollar and unit amounts, except per unit data, are in millions)

1. OPERATIONS AND ORGANIZATION:

The consolidated financial statements and notes thereto of Energy Transfer Partners, L.P., and its subsidiaries (the “Partnership,” “we” or “ETP”) presented herein for the years ended December 31, 2013, 2012 and 2011, have been prepared in accordance with GAAP and pursuant to the rules and regulations of the SEC. We consolidate all majority-owned subsidiaries and subsidiaries we control, even if we do not have a majority ownership. All significant intercompany transactions and accounts are eliminated in consolidation. Management has evaluated subsequent events through the date the financial statements were issued.

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

Certain prior period amounts have been reclassified to conform to the 2013 presentation. These reclassifications had no impact on net income or total equity. In October 2012, we sold Canyon and the results of continuing operations of Canyon have been reclassified to income (loss) from discontinued operations and the prior year amounts have been restated to present Canyon’s operations as discontinued operations. Canyon was previously included in our midstream segment. In 2013, Southern Union sold its distribution operations. The results of operations of the distribution operations have been reported as income (loss) from discontinued operations. The assets and liabilities of the disposal group have been reported as assets and liabilities held for sale as of December 31, 2012.

In accordance with GAAP, we have accounted for the Holdco Transaction (described in Note 3), 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.

We are managed by our general partner, ETP GP, which is in turn managed by its general partner, ETP LLC. ETE, a publicly traded master limited partnership, owns ETP LLC, the general partner of our General Partner. The consolidated financial statements of the Partnership presented herein include our operating subsidiaries described below.

Business Operations

Our activities are primarily conducted through our operating subsidiaries (collectively, the “Operating Companies”) as follows:

- ETC OLP, a Texas limited partnership primarily engaged in midstream and intrastate transportation and storage natural gas operations. ETC OLP owns and operates, through its wholly and majority-owned subsidiaries, natural gas gathering systems, intrastate natural gas pipeline systems and gas processing plants and is engaged in the business of purchasing, gathering, transporting, processing, and marketing natural gas and NGLs in the states of Texas, Louisiana, New Mexico and West Virginia. ETC OLP’s intrastate transportation and storage operations primarily focus on transporting natural gas in Texas through our Oasis pipeline, ET Fuel System, East Texas pipeline and HPL System. ETC OLP’s midstream operations focus on the gathering, compression, treating, conditioning and processing of natural gas, primarily on or through our Southeast Texas System, Eagle Ford System, North Texas System and Northern Louisiana assets. ETC OLP also owns a 70% interest in Lone Star and also owns a convenience store operator with approximately 300 company-owned and dealer locations.
- ET Interstate, a Delaware limited liability company with revenues consisting primarily of fees earned from natural gas transportation services and operational gas sales. ET Interstate is the parent company of:
    - Transwestern, a Delaware limited liability company engaged in interstate transportation of natural gas. Transwestern’s revenues consist primarily of fees earned from natural gas transportation services and operational gas sales.
    - ETC FEP, a Delaware limited liability company that directly owns a 50% interest in FEP, which owns 100% of the Fayetteville Express interstate natural gas pipeline.
    - ETC Tiger, a Delaware limited liability company engaged in interstate transportation of natural gas.

- CrossCountry, a Delaware limited liability company that indirectly owns a 50% interest in Citrus Corp., which owns 100% of the FGT interstate natural gas pipeline.

- ETC Compression, a Delaware limited liability company engaged in natural gas compression services and related equipment sales.
- Sunoco Logistics, a publicly traded Delaware limited partnership that owns and operates a logistics business, consisting of refined products and crude oil pipelines, terminalling and storage assets, and refined products and crude oil acquisition and marketing assets.
- Holdco, a Delaware limited liability company that indirectly owns Panhandle and Sunoco. As discussed in Note 3, ETP acquired ETE's 60% interest in Holdco on April 30, 2013. Panhandle and Sunoco operations are described as follows:
  - Panhandle owns and operates assets in the regulated and unregulated natural gas industry and is primarily engaged in the transportation, storage and distribution of natural gas in the United States. As discussed in Note 3, on April 30, 2013, Southern Union completed its contribution to Regency of all of the issued and outstanding membership interests in Southern Union Gathering Company, LLC, and its subsidiaries, including SUGS. Also, as discussed in Note 3, Southern Union completed its sale of the assets of MGE and NEG in 2013. Additionally, as discussed in Note 3, in January 2014, Panhandle consummated a merger with Southern Union, the indirect parent of Panhandle, and PEPL Holdings, the sole limited partner of Panhandle, pursuant to which each of Southern Union and PEPL Holdings were merged with and into Panhandle, with Panhandle surviving the merger.
  - Sunoco owns and operates retail marketing assets, which sell gasoline and middle distillates at retail and operates convenience stores in 24 states, primarily on the east coast and in the midwest region of the United States.

Our financial statements reflect the following reportable business segments:

- intrastate transportation and storage;
- interstate transportation and storage;
- midstream;
- NGL transportation and services;
- investment in Sunoco Logistics;
- retail marketing; and
- all other.

2. ESTIMATES, SIGNIFICANT ACCOUNTING POLICIES AND BALANCE SHEET DETAIL:

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 operations 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 estimated operating results 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 or installation. 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. Fuel retained for a fee 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 our 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, (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, (iv) purchasing all or a specified percentage of natural gas and/or NGL delivered from producers and treating or processing our plant facilities, and (v) making other direct purchases of natural gas and/or NGL at specified delivery points to meet operational or marketing obligations. 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.

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.

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.

Terminalling and storage revenues are recognized at the time the services are provided. Pipeline revenues are recognized upon delivery of the barrels to the location designated by the shipper. Crude oil acquisition and marketing revenues, as well as refined product marketing revenues, are recognized when title to the product is transferred to the customer. Revenues are not recognized for crude oil exchange transactions, which are entered into primarily to acquire crude oil of a desired quality or to reduce transportation costs by taking delivery closer to end markets. Any net differential for exchange transactions is recorded as an adjustment of inventory costs in the purchases component of cost of products sold and operating expenses in the statements of operations.

Our retail marketing segment sells gasoline and diesel in addition to a broad mix of merchandise such as groceries, fast foods and beverages at its convenience stores. In addition, some of Sunoco's retail outlets provide a variety of car care services. Revenues related to the sale of products are recognized when title passes, while service revenues are recognized when services are provided. Title passage generally occurs when products are shipped or delivered in accordance with the terms of the respective sales agreements. In addition, revenues are not recognized until sales prices are fixed or determinable and collectability is reasonably assured.

Regulatory Accounting – Regulatory Assets and Liabilities

Our interstate transportation and storage segment is subject to regulation by certain state and federal authorities, and certain subsidiaries in that segment have accounting policies that conform to the accounting requirements and ratemaking practices of the regulatory authorities. The application of these accounting policies allows certain of our regulated entities 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 these entities, 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.

Southern Union recorded regulatory assets with respect to its distribution segment operations. At December 31, 2012, we had $123 million of regulatory assets included in the consolidated balance sheet as non-current assets held for sale. Southern Union's distribution operations were sold in 2013.

Although Panhandle's natural gas transmission systems and storage operations are subject to the jurisdiction of FERC in accordance with the Natural Gas Act of 1938 and Natural Gas Policy Act of 1978, it does not currently apply regulatory accounting policies in accounting for its operations. In 1999, prior to its acquisition by Southern Union, Panhandle discontinued the application of regulatory accounting policies primarily due to the level of discounting from tariff rates and its inability to recover specific costs.

Cash, Cash Equivalents and Supplemental Cash Flow Information

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

We place our cash deposits and temporary cash investments with high credit quality financial institutions. At times, our cash and cash equivalents may be uninsured or in deposit accounts that exceed the Federal Deposit Insurance Corporation insurance limit.

The net change in operating assets and liabilities (net of acquisitions) included in cash flows from operating activities is comprised as follows:

	Years Ended December 31,		
	2013	2012	2011
Accounts receivable	$ (458)	$ 300	$ 3
Accounts receivable from related companies	(17)	(50)	(28)
Inventories	(256)	(253)	68
Exchanges receivable	(24)	11	3
Other current assets	(56)	571	(62)
Other non-current assets, net	(22)	(53)	7
Accounts payable	525	(979)	31
Accounts payable to related companies	(122)	100	6
Exchanges payable	131	—	3
Accrued and other current liabilities	152	(151)	60
Other non-current liabilities	151	25	—
Price risk management assets and liabilities, net	(150)	4	75
Net change in operating assets and liabilities, net of effects of acquisitions and deconsolidations	$ (146)	$ (475)	$ 166

Non-cash investing and financing activities and supplemental cash flow information are as follows:

	Years Ended December 31,		
	2013	2012	2011
NON-CASH INVESTING ACTIVITIES:			
Accrued capital expenditures	$ 167	$ 359	$ 202
AmeriGas limited partner interest received in exchange for contribution of Propane Business	$ —	$ 1,123	$ —
Regency common and Class F units received in exchange for contribution of SUGS	$ 961	$ —	$ —
NON-CASH FINANCING ACTIVITIES:			
Long-term debt assumed and non-compete agreement notes payable issued in acquisitions	$ —	$ 6,658	$ 4
Issuance of Common Units in connection with acquisitions	$ —	$ 2,295	$ 3
Issuance of Common Units in connection with the Holdco Acquisition	$ 2,464	$ —	$ —
Issuance of Class H Units	$ 1,514	$ —	$ —
Contributions receivable related to noncontrolling interest	$ 13	$ 23	$ —
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid for interest, net of interest capitalized	$ 903	$ 678	$ 476
Cash paid for income taxes	$ 57	$ 22	$ 24

Accounts Receivable

Our midstream, NGL and intrastate transportation and storage operations deal with counterparties that are typically either investment grade or are otherwise secured with a letter of credit or other form of security (corporate guaranty prepayment or master setoff agreement). Management reviews midstream and intrastate transportation and storage accounts receivable balances bi-weekly. Credit limits are assigned and monitored for all counterparties of the midstream and intrastate transportation and storage operations. Bad debt expense related to these receivables is recognized at the time an account is deemed uncollectible.

Our investment in Sunoco Logistics segment extends credit terms to certain customers after review of various credit indicators, including the customer's credit rating. Outstanding customer receivable balances are regularly reviewed for possible non-payment indicators and reserves are recorded for doubtful accounts based upon management's estimate of collectability at the time of review. Actual balances are charged against the reserve when all collection efforts have been exhausted.

Our interstate transportation and storage operations have a concentration of customers in the electric and gas utility industries as well as natural gas producers. This concentration of customers may impact our overall exposure to credit risk, either positively or negatively, in that the customers may be similarly affected by changes in economic or other conditions. From time to time, specifically identified customers having perceived credit risk are required to provide prepayments or other forms of collateral. Management believes that the portfolio of receivables, which includes regulated electric utilities, regulated local distribution companies and municipalities, is subject to minimal credit risk. Our interstate transportation and storage operations establish an allowance for doubtful accounts on trade receivables based on the expected ultimate recovery of these receivables and consider many factors including historical customer collection experience, general and specific economic trends and known specific issues related to individual customers, sectors and transactions that might impact collectability.

Our retail marketing segment extends credit to customers after a review of credit rating and other credit indicators. Management records reserves for bad debt by computing a proportion of average write-off activity over the past five years in comparison to the outstanding balance in accounts receivable. This proportion is then applied to the accounts receivable balance at the end of the reporting period to calculate a current estimate of what is uncollectible. The credit department and business line managers make the decision to write off an account, based on understanding of the potential collectability.

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

Inventories

Inventories consist principally of natural gas held in storage, crude oil, petroleum and chemical products. Natural gas held in storage is valued at the lower of cost or market utilizing the weighted-average cost method. The cost of crude oil and petroleum and chemical products is determined using the last-in, first out method. The cost of appliances, parts and fittings is determined by the first-in, first-out method.

Inventories consisted of the following:

	December 31,	
	2013	2012
Natural gas and NGLs	$ 519	$ 334
Crude oil	488	418
Refined products	597	572
Appliances, parts and fittings, and other	161	171
Total inventories	$ 1,765	$ 1,495

We utilize commodity derivatives to manage price volatility associated with our natural gas inventory. Changes in fair value of designated hedged inventory are recorded in inventory on our consolidated balance sheets and cost of products sold in our consolidated statements of operations.

Exchanges

Exchanges consist of natural gas and NGL delivery imbalances (over and under deliveries) with others. These amounts, which are valued at market prices or weighted average market prices pursuant to contractual imbalance agreements, turn over monthly and are recorded as exchanges receivable or exchanges payable on our consolidated balance sheets. These imbalances are generally settled by deliveries of natural gas or NGLs, but may be settled in cash, depending on contractual terms.

Other Current Assets

Other current assets consisted of the following:

	December 31,	
	2013	2012
Deposits paid to vendors	$ 49	$ 41
Prepaid and other	261	293
Total other current assets	$ 310	$ 334

Property, Plant and Equipment

Property, plant and equipment are stated at cost less accumulated depreciation. Depreciation is computed using the straight-line method over the estimated useful or FERC mandated lives of the assets, if applicable. 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 our consolidated statements of operations.

We review property, plant and equipment for impairment whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. If such a review should indicate that the carrying amount of long-lived assets is not recoverable, we reduce the carrying amount of such assets to fair value. A write down of the carrying amounts of the Canyon assets to their fair values was recorded for approximately $128 million during the year ended December 31, 2012.

Capitalized interest is included for pipeline construction projects, except for certain interstate projects for which an allowance for funds used during construction ("AFUDC") is accrued. Interest is capitalized based on the current borrowing rate of our revolving credit facility when the related costs are incurred. AFUDC is calculated under guidelines prescribed by the FERC and capitalized as part of the cost of utility plant for interstate projects. It represents the cost of servicing the capital invested in construction work-in-process. AFUDC is segregated into two component parts – borrowed funds and equity funds.

Components and useful lives of property, plant and equipment were as follows:

	December 31, 2013	December 31, 2012
Land and improvements	$ 878	$ 551
Buildings and improvements (5 to 45 years)	900	673
Pipelines and equipment (5 to 83 years)	16,966	17,031
Natural gas and NGL storage facilities (5 to 46 years)	1,083	1,057
Bulk storage, equipment and facilities (2 to 83 years)	1,933	1,745
Tanks and other equipment (5 to 40 years)	1,685	1,187
Retail equipment (3 to 99 years)	450	258
Vehicles (1 to 25 years)	124	135
Right of way (20 to 83 years)	1,901	2,042
Furniture and fixtures (2 to 25 years)	48	65
Linepack	116	116
Pad gas	52	58
Other (1 to 48 years)	626	806
Construction work-in-process	1,668	1,688
	28,430	27,412
Less – Accumulated depreciation	(2,483)	(1,639)
Property, plant and equipment, net	$ 25,947	$ 25,773

We recognized the following amounts of depreciation expense for the periods presented:

	Years Ended December 31, 2013	2012	2011
Depreciation expense[(1)]	$ 944	$ 615	$ 380
Capitalized interest, excluding AFUDC	$ 43	$ 99	$ 11

(1) Depreciation expense amounts have been adjusted by $26 million for the year ended December 31, 2011 to present Canyon's operations as discontinued operations.

Advances to and Investments in Unconsolidated Affiliates

We own interests in a number of related businesses that are accounted for by the equity method. In general, we use the equity method of accounting for an investment for which we exercise significant influence over, but do not control, the investee's operating and financial policies.

Goodwill

Goodwill is tested for impairment annually or more frequently if circumstances indicate that goodwill might be impaired. Our annual impairment test is performed as of August 31 for subsidiaries in our intrastate transportation and storage and midstream segments and during the fourth quarter for subsidiaries in our interstate transportation and storage, NGL transportation and services, and retail marketing segments and all others. We recorded goodwill impairments for the periods presented in these consolidated financial statements.

Changes in the carrying amount of goodwill were as follows:

	Intrastate Transportation and Storage	Interstate Transportation and Storage	Midstream	NGL Transportation and Services	Investment in Sunoco Logistics	Retail Marketing	All Other	Total
Balance, December 31, 2011	$ 10	$ 99	$ 37	$ 432	$ —	$ —	$ 642	$ 1,220
Goodwill acquired	—	1,785	338	—	1,368	1,272	375	5,138
Goodwill sold in deconsolidation of Propane Business	—	—	—	—	—	—	(619)	(619)
Goodwill allocated to the disposal group	—	—	—	—	—	—	(133)	(133)
Balance, December 31, 2012	10	1,884	375	432	1,368	1,272	265	5,606
Goodwill acquired	—	—	—	—	—	156	—	156
Goodwill disposed	—	—	(337)	—	—	—	—	(337)
Goodwill impairment	—	(689)	—	—	—	—	—	(689)
Other	—	—	(2)	—	(22)	17	—	(7)
Balance, December 31, 2013	$ 10	$ 1,195	$ 36	$ 432	$ 1,346	$ 1,445	$ 265	$ 4,729

Goodwill is recorded at the acquisition date based on a preliminary purchase price allocation and generally may be adjusted when the purchase price allocation is finalized. We recorded a net decrease in goodwill of $877 million during the year ended December 31, 2013 primarily due to Trunkline LNG's goodwill impairment of $689 million (see below) and a decrease of $337 million as a result of the SUGS Contribution (see Note 3). These decreases were offset by additional goodwill of $156 million from acquisitions in 2013. This additional goodwill is not expected to be deductible for tax purposes.

During the fourth quarter of 2013, we performed a goodwill impairment test on our Trunkline LNG reporting unit. In accordance with GAAP, we performed step one of the goodwill impairment test and determined that the estimated fair value of the Trunkline LNG reporting unit was less than its carrying amount primarily due to changes related to (i) the structure and capitalization of the planned LNG export project at Trunkline LNG's Lake Charles facility, (ii) an analysis of current macroeconomic factors, including global natural gas prices and relative spreads, as of the date of our assessment, (iii) judgments regarding the prospect of obtaining regulatory approval for a proposed LNG export project and the uncertainty associated with the timing of such approvals, and (iv) changes in assumptions related to potential future revenues from the import facility and the proposed export facility. An assessment of these factors in the fourth quarter of 2013 led to a conclusion that the estimated fair value of the Trunkline LNG reporting unit was less than its carrying amount. We then applied the second step in the goodwill impairment test, allocating the estimated fair value of the reporting unit among all of the assets and liabilities of the reporting unit in a hypothetical purchase price allocation. The assets and liabilities of the reporting unit had recently been measured at fair value in 2012 as a result of the acquisition of Southern Union, and those estimated fair values had been recorded at the reporting unit through the application of "push-down" accounting. For purposes of the hypothetical purchase price allocation used in the goodwill impairment test, we estimated the fair value of the assets and liabilities of the reporting unit in a manner similar to the original purchase price allocation. In allocating value to the property, plant and equipment, we used current replacement costs adjusted for assumed depreciation. We also included the estimated fair value of working capital and identifiable intangible assets in the reporting unit. We adjusted deferred income taxes based on these estimated fair values. Based on this hypothetical purchase price allocation, estimated goodwill was $184 million, which was less than the balance of $873 million that had originally been recorded by the reporting unit through "push-down" accounting in 2012. As a result, we recorded a goodwill impairment of $689 million during the fourth quarter of 2013.

No other goodwill impairments were identified or recorded for our reporting units.

Intangible Assets

Intangible assets are stated at cost, net of amortization computed on the straight-line method. We eliminate from our balance sheet the gross carrying amount and the related accumulated amortization for any fully amortized intangibles in the year they are fully amortized.

Components and useful lives of intangible assets were as follows:

	December 31, 2013		December 31, 2012	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Amortizable intangible assets:				
Customer relationships, contracts and agreements (3 to 46 years)	$ 1,393	$ (164)	$ 1,290	$ (80)
Patents (9 years)	48	(6)	48	(1)
Other (10 to 15 years)	4	(1)	4	(1)
Total amortizable intangible assets	$ 1,445	$ (171)	$ 1,342	$ (82)
Non-amortizable intangible assets:				
Trademarks	294	—	301	—
Total intangible assets	$ 1,739	$ (171)	$ 1,643	$ (82)

Aggregate amortization expense of intangible assets was as follows:

	Years Ended December 31,		
	2013	2012	2011
Reported in depreciation and amortization	$ 88	$ 36	$ 24

Estimated aggregate amortization expense for the next five years is as follows:

Years Ending December 31:	
2014	$ 93
2015	93
2016	93
2017	93
2018	92

We review amortizable intangible assets for impairment whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. If such a review should indicate that the carrying amount of amortizable intangible assets is not recoverable, we reduce the carrying amount of such assets to fair value. We review non-amortizable intangible assets for impairment annually, or more frequently if circumstances dictate.

Other Non-Current Assets, net

Other non-current assets, net are stated at cost less accumulated amortization. Other non-current assets, net consisted of the following:

	December 31,	
	2013	2012
Unamortized financing costs (3 to 30 years)	$ 70	$ 54
Regulatory assets	86	87
Deferred charges	144	140
Restricted funds	378	—
Other	88	76
Total other non-current assets, net	$ 766	$ 357

Restricted funds primarily consisted of restricted cash held in our wholly-owned captive insurance companies.

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 estimate 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, 2013 and 2012 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.

Below is a schedule of AROs by entity recorded as other non-current liabilities in ETP's consolidated balance sheet:

	December 31,	
	2013	2012
Southern Union	$ 55	$ 46
Sunoco	84	53
Sunoco Logistics	41	41
	$ 180	$ 140

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, 2013, there were no legally restricted funds for the purpose of settling AROs.

Accrued and Other Current Liabilities

Accrued and other current liabilities consisted of the following:

	December 31,	
	2013	2012
Interest payable	$ 294	$ 256
Customer advances and deposits	126	44
Accrued capital expenditures	166	356
Accrued wages and benefits	155	236
Taxes payable other than income taxes	214	203
Income taxes payable	3	40
Deferred income taxes	119	130
Other	351	297
Total accrued and other current liabilities	$ 1,428	$ 1,562

Deposits or advances are received from our customers as prepayments for natural gas deliveries in the following month. Prepayments and security deposits may also be required when customers exceed their credit limits or do not qualify for open credit.

Environmental Remediation

We accrue environmental remediation costs for work at identified sites where an assessment has indicated that cleanup costs are probable and reasonably estimable. Such accruals are undiscounted and are based on currently available information, estimated timing of remedial actions and related inflation assumptions, existing technology and presently enacted laws and regulations. If a range of probable environmental cleanup costs exists for an identified site, the minimum of the range is accrued unless some other point in the range is more likely in which case the most likely amount in the range is accrued.

Fair Value of Financial Instruments

The carrying amounts of cash and cash equivalents, accounts receivable and accounts payable approximate their fair value. Price risk management assets and liabilities are recorded at fair value.

Based on the estimated borrowing rates currently available to us and our subsidiaries for loans with similar terms and average maturities, the aggregate fair value and carrying amount of our debt obligations as of December 31, 2013 was $17.69 billion and $17.09 billion, respectively. As of December 31, 2012, the aggregate fair value and carrying amount of our debt obligations was $17.84 billion and $16.22 billion, respectively. The fair value of our consolidated debt obligations is a Level 2 valuation based on the observable inputs used for similar liabilities.

We have 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 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. During the period ended December 31, 2013, no transfers were made between any levels within the fair value hierarchy.

The following tables summarize the fair value of our financial assets and liabilities measured and recorded at fair value on a recurring basis as of December 31, 2013 and 2012 based on inputs used to derive their fair values:

	Fair Value Total	Fair Value Measurements at December 31, 2013	
		Level 1	Level 2
Assets:			
Interest rate derivatives	$ 47	$ —	$ 47
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	5	5	—
Swing Swaps IFERC	8	1	7
Fixed Swaps/Futures	201	201	—
Power:			
Forwards	3	—	3
Natural Gas Liquids – Forwards/Swaps	5	5	—
Refined Products – Futures	5	5	—
Total commodity derivatives	227	217	10
Total assets	$ 274	$ 217	$ 57
Liabilities:			
Interest rate derivatives	$ (95)	$ —	$ (95)
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	(4)	(4)	—
Swing Swaps IFERC	(6)	—	(6)
Fixed Swaps/Futures	(201)	(201)	—
Forward Physical Swaps	(1)	—	(1)
Power:			
Forwards	(1)	—	(1)
Natural Gas Liquids – Forwards/Swaps	(5)	(5)	—
Refined Products – Futures	(5)	(5)	—
Total commodity derivatives	(223)	(215)	(8)
Total liabilities	$ (318)	$ (215)	$ (103)

	Fair Value Total	Fair Value Measurements at December 31, 2012	
		Level 1	Level 2
Assets:			
Interest rate derivatives	$ 55	$ —	$ 55
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	11	11	—
Swing Swaps IFERC	3	—	3
Fixed Swaps/Futures	96	94	2
Options – Puts	1	—	1
Options – Calls	3	—	3
Forward Physical Swaps	1	—	1
Power:			
Forwards	27	—	27
Futures	1	1	—
Options – Calls	2	—	2
Natural Gas Liquids – Swaps	1	1	—
Refined Products – Futures	5	1	4
Total commodity derivatives	151	108	43
Total assets	$ 206	$ 108	$ 98
Liabilities:			
Interest rate derivatives	$ (223)	$ —	$ (223)
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	(18)	(18)	—
Swing Swaps IFERC	(2)	—	(2)
Fixed Swaps/Futures	(103)	(94)	(9)
Options – Puts	(1)	—	(1)
Options – Calls	(3)	—	(3)
Power:			
Forwards	(27)	—	(27)
Futures	(2)	(2)	—
Natural Gas Liquids – Swaps	(3)	(3)	—
Refined Products – Futures	(8)	(1)	(7)
Total commodity derivatives	(167)	(118)	(49)
Total liabilities	$ (390)	$ (118)	$ (272)

At December 31, 2013, the fair value of the Trunkline LNG reporting unit was classified as Level 3 of the fair value hierarchy due to the significance of unobservable inputs developed using company-specific information. We used the income approach to measure the fair value of the Trunkline LNG reporting unit. Under the income approach, we calculated the fair value based on the present value of the estimated future cash flows. The discount rate used, which was an unobservable input, was based on the weighted-average cost of capital adjusted for the relevant risk associated with business-specific characteristics and the uncertainty related to the business's ability to execute on the projected cash flows.

Contributions in Aid of Construction Costs

On certain of our capital projects, third parties are obligated to reimburse us for all or a portion of project expenditures. The majority of such arrangements are associated with pipeline construction and production well tie-ins. Contributions in aid of construction costs ("CIAC") are netted against our project costs as they are received, and any CIAC which exceeds our total project costs, is recognized as other income in the period in which it is realized.

Shipping and Handling Costs

Shipping and handling costs related to fuel sold are included in cost of products sold. Shipping and handling costs related to fuel consumed for compression and treating are included in operating expenses and are as follows:

	Years Ended December 31,		
	2013	2012	2011
Shipping and handling costs – recorded in operating expenses	$ 28	$ 25	$ 40

Costs and Expenses

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

We record the collection of taxes to be remitted to government authorities on a net basis except for our retail marketing segment in which consumer excise taxes on sales of refined products and merchandise are included in both revenues and costs and expenses in the consolidated statements of operations, with no effect on net income (loss). Excise taxes collected by our retail marketing segment were $2.22 billion and $573 million for the years ended December 31, 2013 and 2012, respectively.

Income Taxes

ETP is a publicly traded limited partnership and is not taxable for federal and most state income tax purposes. As a result, our earnings or losses, to the extent not included in a taxable subsidiary, for federal and most state purposes are included in the tax returns of the individual partners. Net earnings for financial statement purposes may differ significantly from taxable income reportable to Unitholders as a result of differences between the tax basis and financial basis of assets and liabilities, differences between the tax accounting and financial accounting treatment of certain items, and due to allocation requirements related to taxable income under our Second Amended and Restated Agreement of Limited Partnership (the "Partnership Agreement").

As a publicly traded limited partnership, we are subject to a statutory requirement that our "qualifying income" (as defined by the Internal Revenue Code, related Treasury Regulations, and IRS pronouncements) exceed 90% of our total gross income, determined on a calendar year basis. If our qualifying income does not meet this statutory requirement, ETP would be taxed as a corporation for federal and state income tax purposes. For the years ended December 31, 2013, 2012 and 2011, our qualifying income met the statutory requirement.

The Partnership conducts certain activities through corporate subsidiaries which are subject to federal, state and local income taxes. Holdco, which owns Sunoco and Southern Union, is a corporate subsidiary. The Partnership and its corporate subsidiaries account for income taxes under the asset and liability method.

Under this method, deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using enacted tax rates in effect for the year in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rate is recognized in earnings in the period that includes the enactment date. Valuation allowances are established when necessary to reduce deferred tax assets to the amounts more likely than not to be realized.

The determination of the provision for income taxes requires significant judgment, use of estimates, and the interpretation and application of complex tax laws. Significant judgment is required in assessing the timing and amounts of deductible and taxable items and the probability of sustaining uncertain tax positions. The benefits of uncertain tax positions are recorded in our financial statements only after determining a more-likely-than-not probability that the uncertain tax positions will withstand challenge, if any, from taxing authorities. When facts and circumstances change, we reassess these probabilities and record any changes through the provision for income taxes.

Accounting for Derivative Instruments and Hedging Activities

For qualifying hedges, we formally document, designate and assess the effectiveness of transactions that receive hedge accounting treatment and the gains and losses offset related results on the hedged item in the statement of operations. 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.

At inception of a hedge, we formally document the relationship between the hedging instrument and the hedged item, the risk management objectives, and the methods used for assessing and testing effectiveness and how any ineffectiveness will be measured and recorded. We also assess, both at the inception of the hedge and on a quarterly basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows. If we determine that a derivative is no longer highly effective as a hedge, we discontinue hedge accounting prospectively by including changes in the fair value of the derivative in net income for the period.

If we designate a commodity 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 statements 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 statements of operations.

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

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.

We manage a portion of our interest rate exposures by utilizing interest rate swaps and similar instruments. Certain of our interest rate derivatives are accounted for as either cash flow hedges or fair value hedges. For interest rate derivatives accounted for as either cash flow or fair value hedges, we report realized gains and losses and ineffectiveness portions of those hedges in interest expense. For interest rate derivatives not designated as hedges for accounting purposes, we report realized and unrealized gains and losses on those derivatives in "Gains (losses) on interest rate derivatives" in the consolidated statements of operations.

Pensions and Other Postretirement Benefit Plans

Employers are required to recognize in their balance sheets the overfunded or underfunded status of defined benefit pension and other postretirement plans, measured as the difference between the fair value of the plan assets and the benefit obligation (the projected benefit obligation for pension plans and the accumulated postretirement benefit obligation for other postretirement plans). Each overfunded plan is recognized as an asset and each underfunded plan is recognized as a liability. Employers must recognize the change in the funded status of the plan in the year in which the change occurs through AOCI in equity or are reflected as a regulatory asset or regulatory liability for regulated subsidiaries.

Allocation of Income

For purposes of maintaining partner capital accounts, the Partnership Agreement specifies that items of income and loss shall generally be allocated among the partners in accordance with their percentage interests. The capital account provisions of our Partnership Agreement incorporate principles established for U.S. Federal income tax purposes and are not comparable to the partners' capital balances reflected under GAAP in our consolidated financial statements. Our net income for partners' capital and statement of operations presentation purposes is allocated to the General Partner and Limited Partners in accordance with their respective partnership percentages, after giving effect to priority income allocations for incentive distributions, if any, to our General Partner, the holder of the IDRs pursuant to our Partnership Agreement, which are declared and paid following the close of each quarter. Earnings in excess of distributions are allocated to the General Partner and Limited Partners based on their respective ownership interests.

3. ACQUISITIONS, DIVESTITURES AND RELATED TRANSACTIONS:

2014 Transactions

Panhandle Merger

On January 10, 2014, Panhandle consummated a merger with Southern Union, the indirect parent of Panhandle, and PEPL Holdings, the sole limited partner of Panhandle, pursuant to which each of Southern Union and PEPL Holdings were merged with and into Panhandle (the "Panhandle Merger"), with Panhandle surviving the Panhandle Merger. In connection with the Panhandle Merger, Panhandle assumed Southern Union's obligations under its 7.6% Senior Notes due 2024, 8.25% Senior Notes due 2029 and the Junior Subordinated Notes due 2066. At the time of the Panhandle Merger, Southern Union did not have operations of its own, other than its ownership of Panhandle and noncontrolling interest in PEI Power II, LLC, Regency (31.4 million common units and 6.3 million Class F Units), and ETP (2.2 million Common Units). In connection with the Panhandle Merger, Panhandle also assumed PEPL Holdings' guarantee of $600 million of Regency senior notes.

Trunkline LNG Transaction

On February 19, 2014, ETE and ETP completed the transfer to ETE of Trunkline LNG, the entity that owns a LNG regasification facility in Lake Charles, Louisiana, from ETP in exchange for the redemption by ETP of 18.7 million ETP Common Units held by ETE. This transaction was effective as of January 1, 2014. The results of Trunkline LNG's operations have not been presented as discontinued operations and Trunkline LNG's assets and liabilities have not been presented as held for sale in the Partnership's consolidated financial statements due to the expected continuing involvement among the entities.

In connection with ETE's acquisition of Trunkline LNG, ETP agreed to continue to provide management services for ETE through 2015 in relation to both Trunkline LNG's regasification facility and the development of a liquefaction project at Trunkline LNG's facility, for which ETE has agreed to pay incremental management fees to ETP of $75 million per year for the years ending December 31, 2014 and 2015. ETE also agreed to provide additional subsidies to ETP through the relinquishment of future incentive distributions, as discussed further in Note 7.

2013 Transactions

Sale of Southern Union's Distribution Operations

In December 2012, Southern Union entered into a purchase and sale agreement with The Laclede Group, Inc., pursuant to which Laclede Missouri agreed to acquire the assets of Southern Union's MGE division and Laclede Massachusetts agreed to acquire the assets of Southern Union's NEG division (together, the "LDC Disposal Group"). Laclede Gas Company, a subsidiary of The Laclede Group, Inc., subsequently assumed all of Laclede Missouri's rights and obligations under the purchase and sale agreement. In February 2013, The Laclede Group, Inc. entered into an agreement with Algonquin Power & Utilities Corp ("APUC") that allowed a subsidiary of APUC to assume the rights of The Laclede Group, Inc. to purchase the assets of Southern Union's NEG division.

In September 2013, Southern Union completed its sale of the assets of MGE for an aggregate purchase price of $975 million, subject to customary post-closing adjustments. In December 2013, Southern Union completed its sale of the assets of NEG for cash proceeds of $40 million, subject to customary post-closing adjustments, and the assumption of $20 million of debt.

The LDC Disposal Group's operations have been classified as discontinued operations for all periods in the consolidated statements of operations. The assets and liabilities of the LDC Disposal Group were classified as assets and liabilities held for sale at December 31, 2012.

The following table summarizes selected financial information related to Southern Union's distribution operations in 2013 through MGE and NEG's sale dates in September 2013 and December 2013, respectively, and for the period from March 26, 2012 to December 31, 2012:

	Years Ended December 31,	
	2013	2012
Revenue from discontinued operations	$ 415	$ 324
Net income of discontinued operations, excluding effect of taxes and overhead allocations	65	43

SUGS Contribution

On April 30, 2013, Southern Union completed its contribution to Regency of all of the issued and outstanding membership interest in Southern Union Gathering Company, LLC, and its subsidiaries, including SUGS (the "SUGS Contribution"). The general partner and IDRs of Regency are owned by ETE. The consideration paid by Regency in connection with this transaction consisted of (i) the issuance of approximately 31.4 million Regency common units to Southern Union, (ii) the issuance of approximately 6.3 million Regency Class F units to Southern Union, (iii) the distribution of $463 million in cash to Southern Union, net of closing adjustments, and (iv) the payment of $30 million in cash to a subsidiary of ETP. This transaction was between commonly controlled entities; therefore, the amounts recorded in the consolidated balance sheet for the investment in Regency and the related deferred tax liabilities were based on the historical book value of SUGS. In addition, PEPL Holdings, a wholly-owned subsidiary of Southern Union, provided a guarantee of collection with respect to the payment of the principal amounts of Regency's debt related to the SUGS Contribution. The Regency Class F units 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. The Partnership has not presented SUGS as discontinued operations due to the expected continuing involvement with SUGS through affiliate relationships, as well as the direct investment in Regency common and Class F units received, which has been accounted for using the equity method.

Acquisition of ETE's Holdco Interest

On April 30, 2013, ETP acquired ETE's 60% interest in Holdco for approximately 49.5 million of newly issued ETP Common Units and $1.40 billion in cash, less $68 million of closing adjustments (the "Holdco Acquisition"). As a result, ETP now owns 100% of Holdco. ETE, which owns the general partner and IDRs of ETP, agreed to forego incentive distributions on the newly issued ETP units for each of the first eight consecutive quarters beginning with the quarter in which the closing of the transaction occurred and 50% of incentive distributions on the newly issued ETP units for the following eight consecutive quarters. ETP controlled Holdco prior to this acquisition; therefore, the transaction did not constitute a change of control.

2012 Transactions

Southern Union Merger

On March 26, 2012, ETE completed its acquisition of Southern Union. Southern Union was the surviving entity in the merger and operated as a wholly-owned subsidiary of ETE. See below for discussion of Holdco Transaction and ETE's contribution of Southern Union to Holdco.

Under the terms of the merger agreement, Southern Union stockholders received a total of 57 million ETE Common Units and a total of approximately $3.01 billion in cash. Effective with the closing of the transaction, Southern Union's common stock was no longer publicly traded.

Citrus Acquisition

In connection with the Southern Union Merger on March 26, 2012, we completed our acquisition of CrossCountry, a subsidiary of Southern Union which owned an indirect 50% interest in Citrus, the owner of FGT. The total merger consideration was approximately $2.0 billion, consisting of approximately $1.9 billion in cash and approximately 2.2 million ETP Common Units. See Note 4 for more information regarding our equity method investment in Citrus.

Sunoco Merger

On October 5, 2012, ETP completed its merger with Sunoco. Under the terms of the merger agreement, Sunoco shareholders received 55 million ETP Common Units and a total of 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.

Prior to the Sunoco Merger, on September 8, 2012, Sunoco completed the exit from its Northeast refining operations by contributing the refining assets at its Philadelphia refinery and various commercial contracts to PES, a joint venture with The Carlyle Group. Sunoco also permanently idled the main refining processing units at its Marcus Hook refinery in June 2012. The Marcus Hook facility continued to support operations at the Philadelphia refinery prior to commencement of the PES joint venture. Under the terms of the joint venture agreement, The Carlyle Group contributed cash in exchange for a 67% controlling interest in PES. In exchange for contributing its Philadelphia refinery assets and various commercial contracts to the joint venture, Sunoco retained an approximate 33% non-operating noncontrolling interest. The fair value of Sunoco's retained interest in PES, which was $75 million on the date on which the joint venture was formed, was determined based on the equity contributions of The Carlyle Group. Sunoco has indemnified PES for environmental liabilities related to the Philadelphia refinery that arose from the operation of such assets prior the formation of the joint venture. The Carlyle Group will oversee day-to-day operations of PES and the refinery. JPMorgan Chase will provide working capital financing to PES in the form of an asset-backed loan, supply crude oil and other feedstocks to the refinery at the time of processing and purchase certain blendstocks and all finished refined products as they are processed. Sunoco entered into a supply contract for gasoline and diesel produced at the refinery for its retail marketing business.

ETP incurred merger related costs related to the Sunoco Merger of $28 million during the year ended December 31, 2012. Sunoco's revenue included in our consolidated statement of operations was approximately $5.93 billion during October through December 2012. Sunoco's net loss included in our consolidated statement of operations was approximately $14 million during October through December 2012. Sunoco Logistics' revenue included in our consolidated statement of operations was approximately $3.11 billion during October through December 2012. Sunoco Logistics' net income included in our consolidated statement of operations was approximately $145 million during October through December 2012.

Holdco Transaction

Immediately following the closing of the Sunoco Merger in 2012, 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. 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 90.7 million Class F Units representing limited partner interests in ETP ("Class F Units"). The Class F Units were exchanged for Class G Units in 2013 as discussed in Note 7. Pursuant to a stockholders agreement between ETE and ETP, ETP controlled Holdco (prior to ETP's acquisition of ETE's 60% equity interest in Holdco in 2013) and therefore, ETP consolidated Holdco (including Sunoco and Southern Union) in its financial statements subsequent to consummation of the Holdco Transaction.

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.

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.

Summary of Assets Acquired and Liabilities Assumed

We accounted for the Sunoco Merger using the acquisition method of accounting, which requires, among other things, that assets acquired and liabilities assumed be recognized on the balance sheet at their fair values as of the acquisition date. Upon consummation of the Holdco Transaction, we applied the accounting guidance for transactions between entities under common control. In doing so, we recorded the values of assets and liabilities that had been recorded by ETE as reflected below.

The following table summarizes the assets acquired and liabilities assumed as of the respective acquisition dates:

	Sunoco[1]	Southern Union[2]
Current assets	$ 7,312	$ 556
Property, plant and equipment	6,686	6,242
Goodwill	2,641	2,497
Intangible assets	1,361	55
Investments in unconsolidated affiliates	240	2,023
Note receivable	821	—
Other assets	128	163
	19,189	11,536
Current liabilities	4,424	1,348
Long-term debt obligations, less current maturities	2,879	3,120
Deferred income taxes	1,762	1,419
Other non-current liabilities	769	284
Noncontrolling interest	3,580	—
	13,414	6,171
Total consideration	5,775	5,365
Cash received	2,714	37
Total consideration, net of cash received	$ 3,061	$ 5,328

(1) Includes amounts recorded with respect to Sunoco Logistics.

(2) Includes ETP's acquisition of Citrus.

As a result of the Holdco Transaction, we recognized $38 million of merger-related costs during the year ended December 31, 2012 related to Southern Union. Southern Union's revenue included in our consolidated statement of operations was approximately $1.26 billion since the acquisition date to December 31, 2012. Southern Union's net income included in our consolidated statement of operations was approximately $39 million since the acquisition date to December 31, 2012.

Propane Operations

On January 12, 2012, we contributed our propane operations, consisting of HOLP and Titan (collectively, the "Propane Business") to AmeriGas. We received approximately $1.46 billion in cash and approximately 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 of $1.50 billion of intercompany indebtedness owed by AmeriGas to a finance subsidiary that in turn supports the repayment of $1.50 billion of senior notes issued by this AmeriGas finance subsidiary to finance the cash portion of the purchase price.

We have not reflected the Propane Business as discontinued operations as we will have a continuing involvement in this business as a result of the investment in AmeriGas that was transferred as consideration for the transaction.

In June 2012, we sold the remainder of our retail propane operations, consisting of our cylinder exchange business, to a third party. In connection with the contribution agreement with AmeriGas, certain excess sales proceeds from the sale of the cylinder exchange business were remitted to AmeriGas, and we received net proceeds of approximately $43 million.

Sale of Canyon

In October 2012, we sold 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 restated to present Canyon's operations as discontinued operations. A write down of the carrying amounts of the Canyon assets to their fair values was recorded for approximately $132 million during the year ended December 31, 2012. Canyon was previously included in our midstream segment.

2011 Transaction

LDH Acquisition

On May 2, 2011, ETP-Regency Midstream Holdings, LLC ("ETP-Regency LLC"), a joint venture owned 70% by the Partnership and 30% by Regency, acquired all of the membership interest in LDH, from Louis Dreyfus Highbridge Energy LLC for approximately $1.98 billion in cash (the "LDH Acquisition"), including working capital adjustments. The Partnership contributed approximately $1.38 billion to ETP-Regency LLC to fund its 70% share of the purchase price. Subsequent to closing, ETP-Regency LLC was renamed Lone Star.

Lone Star owns and operates a natural gas liquids storage, fractionation and transportation business. Lone Star's storage assets are primarily located in Mont Belvieu, Texas, and its West Texas Pipeline transports NGLs through an intrastate pipeline system that originates in the Permian Basin in west Texas, passes through the Barnett Shale production area in north Texas and terminates at the Mont Belvieu storage and fractionation complex. Lone Star also owns and operates fractionation and processing assets located in Louisiana. The acquisition of LDH by Lone Star expanded the Partnership's asset portfolio by adding an NGL platform with storage, transportation and fractionation capabilities.

We accounted for the LDH Acquisition using the acquisition method of accounting. Lone Star's results of operations are included in our NGL transportation and services segment. Regency's 30% interest in Lone Star is reflected as noncontrolling interest.

Pro Forma Results of Operations

The following unaudited pro forma consolidated results of operations for the years ended December 31, 2012 and 2011 are presented as if the Sunoco Merger, Holdco Transaction and LDH Acquisition had been completed on January 1, 2011.

	Years Ended December 31,	
	2012	2011
Revenues	$ 39,136	$ 36,169
Net income	1,133	1,027
Net income attributable to partners	788	745
Basic net income per Limited Partner unit	$ 1.33	$ 1.24
Diluted net income per Limited Partner unit	$ 1.33	$ 1.24

The pro forma consolidated results of operations include adjustments to:

- include the results of Lone Star, Southern Union and Sunoco beginning January 1, 2011;
- include the incremental expenses associated with the fair value adjustments recorded as a result of applying the acquisition method of accounting;
- include incremental interest expense related to the financing of ETP's proportionate share of the purchase price; and
- reflect noncontrolling interest related to ETE's 60% interest in Holdco during the periods.

The pro forma information is not necessarily indicative of the results of operations that would have occurred had the transactions been made at the beginning of the periods presented or the future results of the combined operations.

4. ADVANCES TO AND INVESTMENTS IN UNCONSOLIDATED AFFILIATES:

Regency

On April 30, 2013, Southern Union completed its contribution to Regency of all of the issued and outstanding membership interest in Southern Union Gathering Company, LLC, and its subsidiaries, including SUGS (see Note 3). The consideration paid by Regency in connection with this transaction included approximately 31.4 million Regency common units, approximately 6.3 million Regency Class F units, the distribution of $463 million in cash to Southern Union, net of closing adjustments, and the payment of $30 million in cash to a subsidiary of ETP. This direct investment in Regency common and Class F units received has been accounted for using the equity method.

The carrying amount of our investment in Regency was $1.41 billion as of December 31, 2013 and was reflected in our all other segment.

Citrus Corp.

On March 26, 2012, ETE consummated the acquisition of Southern Union and, concurrently with the closing of the Southern Union acquisition, CrossCountry, a subsidiary of Southern Union that indirectly owned a 50% interest in Citrus, merged with a subsidiary of ETP and, in connection therewith, ETP paid approximately $1.9 billion in cash and issued $105 million of ETP Common Units (the "Citrus Acquisition") to a subsidiary of ETE. As a result of the consummation of the Citrus Acquisition, ETP owns CrossCountry, which in turn owns a 50% interest in Citrus. The other 50% interest in Citrus is owned by a subsidiary of Kinder Morgan, Inc. Citrus owns 100% of FGT, a natural gas pipeline system that originates in Texas and delivers natural gas to the Florida peninsula.

We recorded our investment in Citrus at $2.0 billion, which exceeded our proportionate share of Citrus' equity by $1.03 billion, all of which is treated as equity method goodwill due to the application of regulatory accounting. The carrying amount of our investment in Citrus was $1.89 billion and $1.98 billion as of December 31, 2013 and 2012, respectively, and was reflected in our interstate transportation and storage segment.

AmeriGas Partners, L.P.

As discussed in Note 3, on January 12, 2012, we received approximately 29.6 million AmeriGas common units in connection with the contribution of our propane operations. On July 12, 2013, we sold 7.5 million AmeriGas common units for net proceeds of $346 million, and as of December 31, 2013, we owned 22.1 million AmeriGas common units representing an approximate 24% limited partner interest.

The carrying amount of our investment in AmeriGas was $746 million and $1.02 billion as of December 31, 2013 and 2012, respectively, and was reflected in our all other segment. As of December 31, 2013, our investment in AmeriGas reflected $439 million in excess of our proportionate share of AmeriGas' limited partners' capital. Of this excess fair value, $184 million is being amortized over a weighted average period of 14 years, and $255 million is being treated as equity method goodwill and non-amortizable intangible assets.

In January 2014, we sold 9.2 million AmeriGas common units for net proceeds of $381 million. Net proceeds from this sale were used to repay borrowings under the ETP Credit Facility and general partnership purposes.

FEP

We have a 50% interest in FEP, a 50/50 joint venture with KMP. FEP owns the Fayetteville Express pipeline, an approximately 185-mile natural gas pipeline that originates in Conway County, Arkansas, continues eastward through White County, Arkansas and terminates at an interconnect with Trunkline Gas Company in Panola County, Mississippi. The carrying amount of our investment in FEP was $144 million and $159 million as of December 31, 2013 and 2012, respectively, and was reflected in our interstate transportation and storage segment.

Summarized Financial Information

The following tables present aggregated selected balance sheet and income statement data for our unconsolidated affiliates, FEP, AmeriGas, Citrus and Regency (on a 100% basis) for all periods presented:

	December 31,	
	2013	2012
Current assets	$ 1,372	$ 878
Property, plant and equipment, net	12,320	8,063
Other assets	6,478	2,529
Total assets	$ 20,170	$ 11,470
Current liabilities	$ 1,455	$ 1,605
Non-current liabilities	10,286	6,143
Equity	8,429	3,722
Total liabilities and equity	$ 20,170	$ 11,470

	Years Ended December 31,		
	2013	2012	2011
Revenue	$ 6,806	$ 4,057	$ 3,337
Operating income	1,043	635	681
Net income	574	338	341

In addition to the equity method investments described above we have other equity method investments which are not significant to our consolidated financial statements.

5. NET INCOME PER LIMITED PARTNER UNIT:

A reconciliation of net income and weighted average units used in computing basic and diluted net income per unit is as follows:

	Years Ended December 31,		
	2013	2012	2011
Income from continuing operations	$ 735	$ 1,757	$ 700
Less: Income from continuing operations attributable to noncontrolling interest	296	62	28
Income from continuing operations, net of noncontrolling interest	439	1,695	672
General Partner's interest in income from continuing operations	505	463	433
Limited Partners' interest in income (loss) from continuing operations	(66)	1,232	239
Additional earnings allocated (to) from General Partner	(2)	1	1
Distributions on employee unit awards, net of allocation to General Partner	(10)	(9)	(8)
Income (loss) from continuing operations available to Limited Partners	$ (78)	$ 1,224	$ 232
Weighted average Limited Partner units – basic	343.4	248.3	207.2
Basic income (loss) from continuing operations per Limited Partner unit	$ (0.23)	$ 4.93	$ 1.12
Dilutive effect of unvested Unit Awards	—	0.7	0.9
Weighted average Limited Partner units, assuming dilutive effect of unvested Unit Awards	343.4	249.0	208.1
Diluted income (loss) from continuing operations per Limited Partner unit	$ (0.23)	$ 4.91	$ 1.12
Basic income (loss) from discontinued operations per Limited Partner unit	$ 0.05	$ (0.50)	$ (0.02)
Diluted income (loss) from discontinued operations per Limited Partner unit	$ 0.05	$ (0.50)	$ (0.02)

6. DEBT OBLIGATIONS:

Our debt obligations consist of the following:

	December 31,	
	2013	2012
ETP Debt		
6.0% Senior Notes due July 1, 2013	$ —	$ 350
8.5% Senior Notes due April 15, 2014	292	292
5.95% Senior Notes due February 1, 2015	750	750
6.125% Senior Notes due February 15, 2017	400	400
6.7% Senior Notes due July 1, 2018	600	600

9.7% Senior Notes due March 15, 2019	400	400
9.0% Senior Notes due April 15, 2019	450	450
4.15% Senior Notes due October 1, 2020	700	—
4.65% Senior Notes due June 1, 2021	800	800
5.20% Senior Notes due February 1, 2022	1,000	1,000
3.60% Senior Notes due February 1, 2023	800	—
4.9% Senior Notes due February 1, 2024	350	—
7.6% Senior Notes due February 1, 2024	277	—
8.25% Senior Notes due November 15, 2029	267	—
6.625% Senior Notes due October 15, 2036	400	400
7.5% Senior Notes due July 1, 2038	550	550
6.05% Senior Notes due June 1, 2041	700	700
6.50% Senior Notes due February 1, 2042	1,000	1,000
5.15% Senior Notes due February 1, 2043	450	—
5.95% Senior Notes due October 1, 2043	450	—
Floating Rate Junior Subordinated Notes due November 1, 2066	546	—
ETP $2.5 billion Revolving Credit Facility due October 27, 2017	65	1,395
Unamortized premiums, discounts and fair value adjustments, net	(34)	(14)
	11,213	9,073
Transwestern Debt		
5.39% Senior Notes due November 17, 2014	88	88
5.54% Senior Notes due November 17, 2016	125	125
5.64% Senior Notes due May 24, 2017	82	82
5.36% Senior Notes due December 9, 2020	175	175
5.89% Senior Notes due May 24, 2022	150	150
5.66% Senior Notes due December 9, 2024	175	175
6.16% Senior Notes due May 24, 2037	75	75
Unamortized premiums, discounts and fair value adjustments, net	(1)	(1)
	869	869
Southern Union Debt[1]		
7.60% Senior Notes due February 1, 2024	82	360
8.25% Senior Notes due November 14, 2029	33	300
Floating Rate Junior Subordinated Notes due November 1, 2066	54	600
Southern Union $700 million Revolving Credit Facility due May 20, 2016	—	210
Unamortized premiums, discounts and fair value adjustments, net	48	49
	217	1,519
Panhandle Debt		
6.05% Senior Notes due August 15, 2013	—	250
6.20% Senior Notes due November 1, 2017	300	300
7.00% Senior Notes due June 15, 2018	400	400
8.125% Senior Notes due June 1, 2019	150	150
7.00% Senior Notes due July 15, 2029	66	66
Term Loan due February 23, 2015	—	455
Unamortized premiums, discounts and fair value adjustments, net	107	136
	1,023	1,757

Sunoco Debt		
4.875% Senior Notes due October 15, 2014	250	250
9.625% Senior Notes due April 15, 2015	250	250
5.75% Senior Notes due January 15, 2017	400	400
9.00% Debentures due November 1, 2024	65	65
Unamortized premiums, discounts and fair value adjustments, net	70	104
	1,035	1,069
Sunoco Logistics Debt		
8.75% Senior Notes due February 15, 2014[(2)]	175	175
6.125% Senior Notes due May 15, 2016	175	175
5.50% Senior Notes due February 15, 2020	250	250
4.65% Senior Notes due February 15, 2022	300	300
3.45% Senior Notes due January 15, 2023	350	—
6.85% Senior Notes due February 15, 2040	250	250
6.10% Senior Notes due February 15, 2042	300	300
4.95% Senior Notes due January 15, 2043	350	—
Sunoco Logistics $200 million Revolving Credit Facility due August 21, 2014	—	26
Sunoco Logistics $35 million Revolving Credit Facility due April 30, 2015	35	20
Sunoco Logistics $350 million Revolving Credit Facility due August 22, 2016	—	93
Sunoco Logistics $1.50 billion Revolving Credit Facility due November 1, 2018	200	—
Unamortized premiums, discounts and fair value adjustments, net	118	143
	2,503	1,732
Note Payable to ETE	—	166
Other	228	32
	17,088	16,217
Less: current maturities	637	609
	$ 16,451	$ 15,608

(1) In connection with the Panhandle Merger, Southern Union's debt obligations were assumed by Panhandle.

(2) Sunoco Logistics' 8.75% Senior Notes due February 15, 2014 were classified as long-term debt as Sunoco Logistics repaid these notes in February 2014 with borrowings under its $1.50 billion credit facility due November 2018.

The following table reflects future maturities of long-term debt for each of the next five years and thereafter. These amounts exclude $308 million in unamortized net premiums and fair value adjustments:

2014	$ 812
2015	1,047
2016	375
2017	1,220
2018	1,205
Thereafter	12,121
Total	$ 16,780

ETP as Co-Obligor of Sunoco Debt

In connection with the Sunoco Merger and Holdco Transaction, ETP became a co-obligor on approximately $965 million of aggregate principal amount of Sunoco's existing senior notes and debentures.

ETP Senior Notes

The ETP Senior Notes were registered under the Securities Act of 1933 (as amended). The Partnership may redeem some or all of the ETP Senior Notes at any time, or from time to time, pursuant to the terms of the indenture and related indenture supplements related to the ETP Senior Notes. The balance is payable upon maturity. Interest on the ETP Senior Notes is paid semi-annually.

The ETP Senior Notes are unsecured obligations of the Partnership and the obligation of the Partnership to repay the ETP Senior Notes is not guaranteed by any of the Partnership's subsidiaries. As a result, the ETP Senior Notes effectively rank junior to any future indebtedness of ours or our subsidiaries that is both secured and unsubordinated to the extent of the value of the assets securing such indebtedness, and the ETP Senior Notes effectively rank junior to all indebtedness and other liabilities of our existing and future subsidiaries.

Transwestern Senior Notes

The Transwestern notes are payable at any time in whole or pro rata in part, subject to a premium or upon a change of control event or an event of default, as defined. The balance is payable upon maturity. Interest is paid semi-annually.

Note Payable – ETE

On March 26, 2012, Southern Union received $221 million from ETE to pay certain expenses in connection with the Merger, including (i) payments made to employees related to outstanding awards of stock options, stock appreciation rights and RSUs; and (ii) payments to certain executives under applicable employment or change in control agreements, which provided for compensation when their employment was terminated in connection with a change in control. In connection with the receipt of the $221 million from ETE, on March 26, 2012, Southern Union entered into an interest-bearing promissory note payable due on or before March 25, 2013. The interest rate under the promissory note was 3.25% and accrued interest was payable monthly in arrears. A payment of $55 million to ETE was made in May 2012, and the outstanding balance of $166 million was assumed by Holdco as of December 31, 2012 and the maturity date of the note payable was extended to January 22, 2014. The note payable outstanding was paid in 2013.

Southern Union Junior Subordinated Notes

The interest rate on the remaining portion of Southern Union's $600 million Junior Subordinated Notes due 2066 is a variable rate based upon the three-month LIBOR rate plus 3.0175%. The balance of the variable rate portion of the Junior Subordinated Notes was $600 million at an effective interest rate of 3.32% at December 31, 2013.

Panhandle Term Loans

A portion of the proceeds from ETP's September 2013 Senior Notes Offering, as discussed below, was used to repay $455 million in borrowings outstanding under the LNG Holdings term loan due February 2015.

January 2013 Senior Notes Offerings

In January 2013, ETP issued $800 million aggregate principal amount of 3.6% Senior Notes due February 2023 and $450 million aggregate principal amount of 5.15% Senior Notes due February 2043. ETP used the net proceeds of $1.24 billion from the offering to repay borrowings outstanding under the ETP Credit Facility and for general partnership purposes.

In January 2013, Sunoco Logistics issued $350 million aggregate principal amount of 3.45% Senior Notes due January 2023 and $350 million aggregate principal amount of 4.95% Senior Notes due January 2043. Sunoco Logistics' used the net proceeds of $691 million from the offering to repay borrowings outstanding under the Sunoco Logistics' Credit Facilities and for general partnership purposes.

September 2013 Senior Notes Offering

In September 2013, ETP issued $700 million aggregate principal amount of 4.15% Senior Notes due October 2020, $350 million aggregate principal amount of 4.90% Senior Notes due February 2024 and $450 million aggregate principal amount of 5.95% Senior Notes due October 2043. ETP used the net proceeds of $1.47 billion from the offering to repay $455 million in borrowings outstanding under the term loan of Panhandle's wholly-owned subsidiary, Trunkline LNG Holdings, LLC, to repay borrowings outstanding under the ETP Credit Facility and for general partnership purposes.

Note Exchange

On June 24, 2013, ETP completed the exchange of approximately $1.09 billion aggregate principal amount of Southern Union's outstanding senior notes, comprising 77% of the principal amount of the 7.6% Senior Notes due 2024, 89% of the principal amount of the 8.25% Senior Notes due 2029 and 91% of the principal amount of the Junior Subordinated Notes due 2066. These notes were exchanged for new notes issued by ETP with the same coupon rates and maturity dates. In conjunction with this transaction, Southern Union entered into intercompany notes payable to ETP, which provide for the reimbursement by Southern Union of ETP's payments under the newly issued notes.

Credit Facilities

ETP Credit Facility

The ETP Credit Facility allows for borrowings of up to $2.5 billion and expires in October 2017. 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.

In November 2013, we amended the ETP Credit Facility to, among other things, (i) extend the maturity date for one additional year to October 2017, (ii) remove the restriction prohibiting unrestricted subsidiaries from owning debt or equity interests in ETP or any restricted subsidiaries of ETP, (iii) amend the covenant limiting fundamental changes to remove the restrictions on mergers or other consolidations of restricted subsidiaries of ETP and to permit ETP to merge with another person and not be the surviving entity provided certain requirements are met, and (iv) amend certain other provisions more specifically set forth in the amendment.

As of December 31, 2013, the ETP Credit Facility had $65 million outstanding, and the amount available for future borrowings was $2.34 billion after taking into account letters of credit of $93 million. The weighted average interest rate on the total amount outstanding as of December 31, 2013 was 1.67%.

Southern Union Credit Facility

Proceeds from the SUGS Contribution were used to repay borrowings under the Southern Union Credit Facility and the facility was terminated.

Sunoco Logistics Credit Facilities

In November 2013, Sunoco Logistics replaced its existing $350 million and $200 million unsecured credit facilities with a new $1.50 billion unsecured credit facility (the "$1.50 billion Credit Facility"). The $1.50 billion Credit Facility contains an accordion feature, under which the total aggregate commitment may be extended to $2.25 billion under certain conditions. Outstanding borrowings under the $350 million and $200 million credit facilities of $119 million at December 31, 2012 were repaid during the first quarter of 2013.

The $1.50 billion Credit Facility, which matures in November 2018, is available to fund Sunoco Logistics' working capital requirements, to finance acquisitions and capital projects, to pay distributions and for general partnership purposes. The $1.50 billion Credit Facility bears interest at LIBOR or the Base Rate, each plus an applicable margin. The credit facility may be prepaid at any time. Outstanding borrowings under this credit facility were $200 million at December 31, 2013.

West Texas Gulf Pipe Line Company, a subsidiary of Sunoco Logistics, has a $35 million revolving 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 $35 million at December 31, 2013.

Covenants Related to Our Credit Agreements

Covenants Related to ETP

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.

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 assets and the payment of dividends and specify a maximum debt to capitalization ratio.

Failure to comply with the various restrictive and affirmative covenants of our revolving credit facilities could require us to pay debt balances prior to scheduled maturity and could negatively impact the Operating Companies' ability to incur additional debt and/or our ability to pay distributions.

Covenants Related to Southern Union

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 that require Southern Union to maintain a certain level of net worth, to meet certain debt to total capitalization ratios and to meet certain ratios of earnings before depreciation, interest and taxes to cash interest expense. 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.

In addition, 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 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

Sunoco Logistics' $1.50 billion credit facility contains various covenants, including limitations on the creation of indebtedness and liens, and other covenants related to the operation and conduct of the business of Sunoco Logistics and its subsidiaries. The credit facility also limits Sunoco Logistics, on a rolling four-quarter basis, to a maximum total consolidated debt to consolidated Adjusted EBITDA ratio, as defined in the underlying credit agreement, of 5.0 to 1, which can generally be increased to 5.5 to 1 during an acquisition period. Sunoco Logistics' ratio of total consolidated debt, excluding net unamortized fair value adjustments, to consolidated Adjusted EBITDA was 2.8 to 1 at December 31, 2013, as calculated in accordance with the credit agreements.

The $35 million credit facility 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, 2013 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 1.12 to 1 and 0.88 to 1, respectively, at December 31, 2013.

We were in compliance with all requirements, tests, limitations, and covenants related to our debt agreements as of December 31, 2013.

7. EQUITY:

Limited Partner interests are represented by Common, Class E Units, Class G Units and Class H Units that entitle the holders thereof to the rights and privileges specified in the Partnership Agreement. As of December 31, 2013, there were issued and outstanding 333.8 million Common Units representing an aggregate 99.3% Limited Partner interest in us. There are also 8.9 million Class E Units and 90.7 million Class G Units outstanding that are reported as treasury units, which units are entitled to receive distributions in accordance with their terms. There are also 50.2 million Class H Units outstanding representing Limited Partner interests owned by ETE Holdings (see "Class H Units" below).

No person is entitled to preemptive rights in respect of issuances of equity securities by us, except that ETP GP has the right, in connection with the issuance of any equity security by us, to purchase equity securities on the same terms as equity securities are issued to third parties sufficient to enable ETP GP and its affiliates to maintain the aggregate percentage equity interest in us as ETP GP and its affiliates owned immediately prior to such issuance.

IDRs represent the contractual right to receive an increasing percentage of quarterly distributions of Available Cash (as defined in our Partnership Agreement) from operating surplus after the minimum quarterly distribution has been paid. Please read "Quarterly Distributions of Available Cash" below. ETP GP, a wholly-owned subsidiary of ETE, owns all of the IDRs.

Common Units

The change in Common Units was as follows:

	Years Ended December 31,		
	2013	2012	2011
Number of Common Units, beginning of period	301.5	225.5	193.2
Common Units issued in connection with public offerings	13.8	15.5	29.4
Common Units issued in connection with certain acquisitions	49.5	57.4	0.1
Common Units redeemed for Class H Units	(50.2)	—	—
Common Units issued in connection with the Distribution Reinvestment Plan	2.3	1.0	0.4
Common Units issued in connection with Equity Distribution Agreements	16.9	1.6	2.0
Repurchase of common Units in open-market transactions	(0.4)	—	—
Issuance of Common Units under equity incentive plans	0.4	0.5	0.4
Number of Common Units, end of period	333.8	301.5	225.5

Our Common Units are registered under the Securities Exchange Act of 1934 (as amended) and are listed for trading on the NYSE. Each holder of a Common Unit is entitled to one vote per unit on all matters presented to the Limited Partners for a vote. In addition, if at any time any person or group (other than our General Partner and its affiliates) owns beneficially 20% or more of all Common Units, any Common Units owned by that person or group may not be voted on any matter and are not considered to be outstanding when sending notices of a meeting of Unitholders (unless otherwise required by law), calculating required votes, determining the presence of a quorum or for other similar purposes under the Partnership Agreement. The Common Units are entitled to distributions of Available Cash as described below under "Quarterly Distributions of Available Cash."

Public Offerings

The following table summarizes our public offerings of Common Units, all of which have been registered under the Securities Act of 1933 (as amended):

Date	Number of Common Units	Price per Unit	Net Proceeds
April 2011	14.2	$ 50.52	$ 695
November 2011	15.2	44.67	660
July 2012	15.5	44.57	671
April 2013	13.8	48.05	657

Proceeds from the offerings listed above were used to repay amounts outstanding under the ETP Credit Facility and/or to fund capital expenditures and capital contributions to joint ventures, and for general partnership purposes.

Equity Distribution Program

From time to time, we have sold Common Units through an equity distribution agreement. Such sales of Common Units are made by means of ordinary brokers' transactions on the NYSE at market prices, in block transactions or as otherwise agreed between us and the sales agent which is the counterparty to the equity distribution agreement.

In January 2013 and May 2013, we entered into equity distribution agreements pursuant to which we may sell from time to time Common Units having aggregate offering prices of up to $200 million and $800 million, respectively. During the year ended December 31, 2013, we issued approximately 16.9 million units for $846 million, net of commissions of $9 million. Approximately $145 million of our Common Units remained available to be issued under the currently effective equity distribution agreements as of December 31, 2013.

Equity Incentive Plan Activity

As discussed in Note 8, we issue Common Units to employees and directors upon vesting of awards granted under our equity incentive plans. Upon vesting, participants in the equity incentive plans may elect to have a portion of the Common Units to which they are entitled withheld by the Partnership to satisfy tax-withholding obligations.

Distribution Reinvestment Program

In April 2011, we filed a registration statement with the SEC covering our Distribution Reinvestment Plan (the "DRIP"). The DRIP provides Unitholders of record and beneficial owners of our Common Units a voluntary means by which they can increase the number of ETP Common Units they own by reinvesting the quarterly cash distributions they would otherwise receive in the purchase of additional Common Units. The registration statement covers the issuance of up to 5.8 million Common Units under the DRIP.

During the years ended December 31, 2013, 2012 and 2011, aggregate distributions of approximately $109 million, $43 million, and $15 million were reinvested under the DRIP resulting in the issuance in aggregate of approximately 3.7 million Common Units. As of December 31, 2013, a total of 2.1 million Common Units remain available to be issued under the existing registration statement.

Class E Units

There are 8.9 million Class E Units outstanding that are reported as treasury units. These Class E Units are entitled to aggregate cash distributions equal to 11.1% of the total amount of cash distributed to all Unitholders, including the Class E Unitholders, up to $1.41 per unit per year, with any excess thereof available for distribution to Unitholders other than the holders of Class E Units in proportion to their respective interests. The Class E Units are treated as treasury units for accounting purposes because they are owned by a subsidiary of Holdco, Heritage Holdings, Inc. Although no plans are currently in place, management may evaluate whether to retire some or all of the Class E Units at a future date.

Class G Units

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 90.7 million, which included 40 million 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 did not have any voting rights. The Class F Units were entitled to aggregate cash distributions equal to 35% of the total amount of cash 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. In April 2013, all of the outstanding Class F Units were exchanged for Class G Units on a one-for-one basis. The Class G Units have terms that are substantially the same as the Class F Units, with the principal difference between the Class G Units and the Class F Units being that allocations of depreciation and amortization to the Class G Units for tax purposes are based on a predetermined percentage and are not contingent on whether ETP has net income or loss. These units are held by a subsidiary and therefore are reflected as treasury units in the consolidated financial statements.

Class H Units

Pursuant to an Exchange and Redemption Agreement previously entered into between ETP, ETE and ETE Holdings, ETP redeemed and cancelled 50.2 million of its Common Units representing limited partner interests (the "Redeemed Units") owned by ETE Holdings on October 31, 2013 in exchange for the issuance by ETP to ETE Holdings of a new class of limited partner interest in ETP (the "Class H Units"), which are generally entitled to (i) allocations of profits, losses and other items from ETP corresponding to 50.05% of the profits, losses, and other items allocated to ETP by Sunoco Partners with respect to the IDRs and general partner interest in Sunoco Logistics held by Sunoco Partners, (ii) distributions from available cash at ETP for each quarter equal to 50.05% of the cash distributed to ETP by Sunoco Partners with respect to the IDRs and general partner interest in Sunoco Logistics held by Sunoco Partners for such quarter and, to the extent not previously distributed to holders of the Class H Units, for any previous quarters and (iii) incremental additional cash distributions in the aggregate amount of $329 million, to be payable by ETP to ETE Holdings over 15 quarters, commencing with the quarter ended September 30, 2013 and ending with the quarter ending March 31, 2017. The incremental cash distributions referred to in clause (iii) of the previous sentence are intended to offset a portion of the IDR subsidies previously granted by ETE to ETP in connection with the Citrus Merger, the Holdco Transaction and the Holdco Acquisition. In connection with the issuance of the Class H Units, ETE and ETP also agreed to certain adjustments to the prior IDR subsidies in order to ensure that the IDR subsidies are fixed amounts for each quarter to which the IDR subsidies are in effect. For a summary of the net IDR subsidy amounts resulting from this transaction, see "Quarterly Distributions of Available Cash" below.

Quarterly Distributions of Available Cash

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

Our distributions of Available Cash from operating surplus, excluding incentive distributions, to our General Partner and Limited Partner interests are based on their respective interests as of the distribution record date. Incentive distributions allocated to our General Partner are determined based on the amount by which quarterly distribution to common Unitholders exceed certain specified target levels, as set forth in our Partnership Agreement.

Distributions declared during the periods presented below are summarized as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2010	February 7, 2011	February 14, 2011	$ 0.89375
March 31, 2011	May 6, 2011	May 16, 2011	0.89375
June 30, 2011	August 5, 2011	August 15, 2011	0.89375
September 30, 2011	November 4, 2011	November 14, 2011	0.89375
December 31, 2011	February 7, 2012	February 14, 2012	0.89375
March 31, 2012	May 4, 2012	May 15, 2012	0.89375
June 30, 2012	August 6, 2012	August 14, 2012	0.89375
September 30, 2012	November 6, 2012	November 14, 2012	0.89375
December 31, 2012	February 7, 2013	February 14, 2013	0.89375
March 31, 2013	May 6, 2013	May 15, 2013	0.89375
June 30, 2013	August 5, 2013	August 14, 2013	0.89375
September 30, 2013	November 4, 2013	November 14, 2013	0.90500
December 31, 2013	February 7, 2014	February 14, 2014	0.92000

Following are incentive distributions ETE has agreed to relinquish:

- In conjunction with the Partnership's Citrus Merger, ETE agreed to relinquish its rights to $220 million of incentive distributions from ETP that ETE would otherwise be entitled to receive over 16 consecutive quarters beginning with the distribution paid on May 15, 2012.
- In conjunction with the Holdco Transaction in October 2012, 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.
- As discussed in Note 3, in connection with the Holdco Acquisition on April 30, 2013, ETE also agreed to relinquish incentive distributions on the newly issued Common Units for the first eight consecutive quarters beginning with the distribution paid on August 14, 2013, and 50% of the incentive distributions for the following eight consecutive quarters.

In addition, the incremental distributions on the Class H Units, which are referred to in "Class H Units" above, were intended to offset a portion of the incentive distribution relinquishments previously granted by ETE to the Partnership. In connection with the issuance of the Class H Units, ETE and the Partnership also agreed to certain adjustments to the incremental distributions on the Class H Units in order to ensure that the net impact of the incentive distribution relinquishments (a portion of which is variable) and the incremental distributions on the Class H Units are fixed amounts for each quarter for which the incentive distribution relinquishments and incremental distributions on the Class H Units are in effect.

In addition to the amounts above, in connection with the Partnership's transfer of Trunkline LNG to ETE in February 2014, ETE agreed to provide additional subsidies to ETP through its relinquishment of incentive distributions of $50 million, $50 million, $45 million and $35 million for the years ending December 31, 2016, 2017, 2018 and 2019, respectively.

Following is a summary of the net amounts by which these incentive distribution relinquishments and incremental distributions on Class H Units would reduce the total distributions that would potentially be made to ETE in future quarters:

	Quarters Ending				
	March 31	June 30	September 30	December 31	Total Year
2014	$ 26.5	$ 26.5	$ 26.5	$ 26.5	$ 106.0
2015	12.5	12.5	13.0	13.0	51.0
2016	18.0	18.0	18.0	18.0	72.0
2017	12.5	12.5	12.5	12.5	50.0
2018	11.25	11.25	11.25	11.25	45.0
2019	8.75	8.75	8.75	8.75	35.0

Sunoco Logistics Quarterly Distributions of Available Cash

Distributions declared during the periods presented below are summarized as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2012	February 8, 2013	February 14, 2013	$ 0.54500
March 31, 2013	May 9, 2013	May 15, 2013	0.57250
June 30, 2013	August 8, 2013	August 14, 2013	0.60000
September 30, 2013	November 8, 2013	November 14, 2013	0.63000
December 31, 2013	February 10, 2014	February 14, 2014	0.66250

Accumulated Other Comprehensive Income (Loss)

The following table presents the components of AOCI, net of tax:

	December 31, 2013	December 31, 2012
Available-for-sale securities	$ 2	$ —
Foreign currency translation adjustment	(1)	—
Net loss on commodity related hedges	(4)	—
Actuarial gain (loss) related to pensions and other postretirement benefits	56	(10)
Equity investments, net	8	(9)
Subtotal	61	(19)
Amounts attributable to noncontrolling interest	—	6
Total AOCI, net of tax	$ 61	$ (13)

The tables below set forth the tax amounts included in the respective components of other comprehensive income (loss) for the periods presented:

	December 31, 2013	December 31, 2012
Net gains on commodity related hedges	$ —	$ 1
Actuarial (gain) loss relating to pension and other postretirement benefits	(39)	5
Total	$ (39)	$ 6

8. UNIT-BASED COMPENSATION PLANS:

ETP Unit-Based Compensation Plan

We have issued equity incentive plans for employees, officers and directors, which provide for various types of awards, including options to purchase ETP Common Units, restricted units, phantom units, Common Units, distribution equivalent rights ("DERs"), Common Unit appreciation rights, and other unit-based awards. As of December 31, 2013, an aggregate total of 0.9 million ETP Common Units remain available to be awarded under our equity incentive plans.

Unit Grants

We have granted restricted unit awards to employees that vest over a specified time period, typically a five-year service vesting requirement, with vesting based on continued employment as of each applicable vesting date. Upon vesting, ETP Common Units are issued. These unit awards entitle the recipients of the unit awards to receive, with respect to each 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. We refer to these rights as "distribution equivalent rights." Under our equity incentive plans, our non-employee directors each receive grants with a five-year service vesting requirement.

Award Activity

The following table shows the activity of the awards granted to employees and non-employee directors:

	Number of Units	Weighted Average Grant-Date Fair Value Per Unit
Unvested awards as of December 31, 2012	1.9	$ 46.95
Awards granted	2.1	50.54
Awards vested	(0.6)	45.62
Awards forfeited	(0.2)	45.72
Unvested awards as of December 31, 2013	3.2	49.65

During the years ended December 31, 2013, 2012 and 2011, the weighted average grant-date fair value per unit award granted was $50.54, $43.93 and $48.35, respectively. The total fair value of awards vested was $26 million, $29 million and $27 million, respectively, based on the market price of ETP Common Units as of the vesting date. As of December 31, 2013, a total of 3.2 million unit awards remain unvested, for which ETP expects to recognize a total of $116 million in compensation expense over a weighted average period of 2.1 years.

Sunoco Logistics' Unit-Based Compensation Plan

Sunoco Logistics' general partner has a long-term incentive plan for employees and directors, which permits the grant of restricted units and unit options of Sunoco Logistics covering an additional 0.6 million Sunoco common units. As of December 31, 2013, a total of 0.6 million Sunoco Logistics restricted units were outstanding for which Sunoco Logistics expects to recognize $21 million of expense over a weighted-average period of 2.8 years.

Related Party Awards

McReynolds Energy Partners, L.P., the general partner of which is owned and controlled by the President of the entity that indirectly owns our General Partner, awarded to certain officers of ETP certain rights related to units of ETE previously issued by ETE to such ETE officer. These rights include the economic benefits of ownership of these ETE units based on a 5 year vesting schedule whereby the officer vested in the ETE units at a rate of 20% per year. As these ETE units 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 were paid by ETP or ETE. As these units were outstanding prior to these awards, these awards did not represent an increase in the number of outstanding units of either ETP or ETE and were not dilutive to cash distributions per unit with respect to either ETP or ETE.

We recognized 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. For the years ended December 31, 2013, 2012 and 2011, we recognized non-cash compensation expense, net of forfeitures, of less than $1 million, $1 million and $2 million, respectively, as a result of these awards. As of December 31, 2013, no rights related to ETE common units remain outstanding.

9. INCOME TAXES:

As a partnership, we are not subject to U.S. federal income tax and most state income taxes. However, the partnership conducts certain activities through corporate subsidiaries which are subject to federal and state income taxes. The components of the federal and state income tax expense (benefit) are summarized as follows:

	Years Ended December 31,		
	2013	2012	2011
Current expense (benefit):			
Federal	$ 51	$ (3)	$ (1)
State	(2)	4	16
Total	49	1	15
Deferred expense:			
Federal	(6)	45	4
State	54	17	—
Total	48	62	4
Total income tax expense from continuing operations	$ 97	$ 63	$ 19

Historically, our effective rate differed from the statutory rate primarily due to Partnership earnings that are not subject to U.S. federal and most state income taxes at the Partnership level. The completion of the Southern Union Merger, Sunoco Merger and Holdco Transaction (see Note 3) significantly increased the activities conducted through corporate subsidiaries. A reconciliation of income tax expense (benefit) at the U.S. statutory rate to the income tax expense (benefit) attributable to continuing operations for the years ended December 31, 2013 and 2012 is as follows:

	December 31, 2013			December 31, 2012		
	Corporate Subsidiaries(1)	Partnership(2)	Consolidated	Corporate Subsidiaries(1)	Partnership(2)	Consolidated
Income tax expense (benefit) at U.S. statutory rate of 35 percent	$ (166)	$ —	$ (166)	$ 1	$ —	$ 1
Increase (reduction) in income taxes resulting from:						
Nondeductible goodwill	241	—	241	—	—	—
Nondeductible executive compensation	—	—	—	28	—	28
State income taxes (net of federal income tax effects)	31	5	36	9	7	16
Other	(13)	(1)	(14)	18	—	18
Income tax from continuing operations	$ 93	$ 4	$ 97	$ 56	$ 7	$ 63

(1) Includes Holdco, Oasis Pipeline Company, Inland Corporation, Mid-Valley Pipeline Company and West Texas Gulf Pipeline Company. The latter three entities were acquired in the Sunoco Merger. Holdco, which was formed via the Sunoco Merger and the Holdco Transaction (see Note 3), includes Sunoco and Southern Union and their subsidiaries. ETE held a 60% interest in Holdco until April 30, 2013. Subsequent to the Holdco Acquisition (see Note 3) on April 30, 2013, ETP owns 100% of Holdco.

(2) Includes ETP and its subsidiaries that are classified as pass-through entities for federal income tax purposes.

Deferred taxes result from the temporary differences between financial reporting carrying amounts and the tax basis of existing assets and liabilities. The table below summarizes the principal components of the deferred tax assets (liabilities) as follows:

	December 31,	
	2013	2012
Deferred income tax assets:		
Net operating losses and alternative minimum tax credit	$ 217	$ 268
Pension and other postretirement benefits	57	127
Long term debt	108	117
Other	104	288
Total deferred income tax assets	486	800
Valuation allowance	(74)	(90)
Net deferred income tax assets	$ 412	$ 710
Deferred income tax liabilities:		
Properties, plants and equipment	$ (1,522)	$ (1,938)
Inventory	(302)	(516)
Investment in unconsolidated affiliates	(2,244)	(1,542)
Trademarks	(180)	(192)
Other	(45)	(128)
Total deferred income tax liabilities	(4,293)	(4,316)
Net deferred income tax liability	(3,881)	(3,606)
Less: current portion of deferred income tax assets (liabilities)	(119)	(130)
Accumulated deferred income taxes	$ (3,762)	$ (3,476)

The completion of the Southern Union Merger, Sunoco Merger and Holdco Transaction (see Note 3) significantly increased the deferred tax assets (liabilities). The table below provides a rollforward of the net deferred income tax liability as follows:

	December 31,	
	2013	2012
Net deferred income tax liability, beginning of year	$ (3,606)	$ (123)
Southern Union acquisition	—	(1,420)
Sunoco acquisition	—	(1,989)
SUGS Contribution to Regency	(115)	—
Tax provision (including discontinued operations)	(111)	(73)
Other	(49)	(1)
Net deferred income tax liability	$ (3,881)	$ (3,606)

Holdco and other corporate subsidiaries have gross federal net operating loss carryforwards of $216 million, all of which will expire in 2032. Holdco has $40 million of federal alternative minimum tax credits which do not expire. Holdco and other corporate subsidiaries have state net operating loss carryforward benefits of $101 million, net of federal tax, which expire between 2013 and 2032. The valuation allowance of $74 million is applicable to the state net operating loss carryforward benefits applicable to Sunoco pre-acquisition periods.

The following table sets forth the changes in unrecognized tax benefits:

	Years Ended December 31,		
	2013	2012	2011
Balance at beginning of year	$ 27	$ 2	$ 2
Additions attributable to acquisitions	—	28	—
Additions attributable to tax positions taken in the current year	—	—	1
Additions attributable to tax positions taken in prior years	406	—	—
Settlements	—	—	(1)
Lapse of statute	(4)	(3)	—
Balance at end of year	$ 429	$ 27	$ 2

As of December 31, 2013, we have $425 million ($418 million after federal income tax benefits) related to tax positions which, if recognized, would impact our effective tax rate. We believe it is reasonably possible that its unrecognized tax benefits may be reduced by $6 million ($5 million, net of federal tax) within the next twelve months due to settlement of certain positions.

Sunoco has historically included certain government incentive payments as taxable income on its federal and state income tax returns. In connection with Sunoco's 2004 through 2011 open statute years, Sunoco has proposed to the IRS that these government incentive payments be excluded from federal taxable income. If Sunoco is fully successful with its claims, it will receive tax refunds of approximately $372 million. However, due to the uncertainty surrounding the claims, a reserve of $372 million was established for the full amount of the claims. Due to the timing of the expected settlement of the claims and the related reserve, the receivable and the reserve for this issue have been netted in the financial statements as of December 31, 2013.

Our policy is to accrue interest expense and penalties on income tax underpayments (overpayments) as a component of income tax expense. During 2013, we recognized interest and penalties of less than $1 million. At December 31, 2013, we have interest and penalties accrued of $6 million, net of tax.

In general, ETP and its subsidiaries are no longer subject to examination by the IRS for tax years prior to 2009, except Sunoco and Southern Union which are no longer subject to examination by the IRS for tax years prior to 2007 and 2004, respectively.

Sunoco has been examined by the IRS for the 2007 and 2008 tax years; however, the statutes remain open for both of these tax years due to carryback of net operating losses. Sunoco is currently under examination for the years 2009 through 2011, but due to the aforementioned carryback, such years also impact Sunoco's tax liability for the years 2004 through 2008. With the exception of the claims regarding government incentive payments discussed above, all issues are resolved. Southern Union is under examination for the tax years 2004 through 2009. As of December 31, 2013, the IRS has proposed only one adjustment for the years under examination. For the 2006 tax year, the IRS is challenging $545 million of the $690 million of deferred gain associated with a like kind exchange involving certain assets of its distribution operations and its gathering and processing operations. We will vigorously defend and believe Southern Union's tax position will prevail against this challenge by the IRS. Accordingly, no unrecognized tax benefit has been recorded with respect to this tax position.

ETP and its subsidiaries also have various state and local income tax returns in the process of examination or administrative appeal in various jurisdictions. We believe the appropriate accruals or unrecognized tax benefits have been recorded for any potential assessment with respect to these examinations.

10. REGULATORY MATTERS, COMMITMENTS, CONTINGENCIES AND ENVIRONMENTAL LIABILITIES:

FERC Audit

The FERC recently completed an audit of PEPL, a subsidiary of Southern Union, for the period from January 1, 2010 through December 31, 2011, to evaluate its compliance with the Uniform System of Accounts as prescribed by the FERC, annual and quarterly financial reporting to the FERC, reservation charge crediting policy and record retention. An audit report was received in August 2013 noting no issues that would have a material impact on the Partnership's historical financial position or results of operations.

Contingent Matters Potentially Impacting the Partnership from Our Investment in Citrus

Florida Gas Pipeline Relocation Costs. The Florida Department of Transportation, Florida's Turnpike Enterprise ("FDOT/FTE") has various turnpike/State Road 91 widening projects that have impacted or may, over time, impact one or more of FGTs' mainline pipelines located in FDOT/FTE rights-of-way. Certain FDOT/FTE projects have been or are the subject of litigation in Broward County, Florida. On November 16, 2012, FDOT paid to FGT the sum of approximately $100 million, representing the amount of the judgment, plus interest, in a case tried in 2011.

On April 14, 2011, FGT filed suit against the FDOT/FTE and other defendants in Broward County, Florida seeking an injunction and damages as the result of the construction of a mechanically stabilized earth wall and other encroachments in FGT easements as part of FDOT/FTE's I-595 project. On August 21, 2013, FGT and FDOT/FTE entered into a settlement agreement pursuant to which, among other things, FDOT/FTE paid FGT approximately $19 million in September, 2013 in settlement of FGT's claims with respect to the I-595 project. The settlement agreement also provided for agreed easement widths for FDOT/FTE right-of-way and for cost sharing between FGT and FDOT/FTE for any future relocations. Also in September 2013, FDOT/FTE paid FGT an additional approximate $1 million for costs related to the aforementioned turnpike/State Road 91 case tried in 2011.

FGT will continue to seek rate recovery in the future for these types of costs to the extent not reimbursed by the FDOT/FTE. There can be no assurance that FGT will be successful in obtaining complete reimbursement for any such relocation costs from the FDOT/FTE or from its customers or that the timing of such reimbursement will fully compensate FGT for its costs.

Contingent Residual Support Agreement – AmeriGas

In connection with the closing of the contribution of its propane operations in January 2012, ETP agreed to provide contingent, residual support of $1.55 billion of intercompany borrowings made by AmeriGas and certain of its affiliates with maturities through 2022 from a finance subsidiary of AmeriGas that have maturity dates and repayment terms that mirror those of an equal principal amount of senior notes issued by this finance company subsidiary to third party purchases.

PEPL Holdings Guarantee of Collection

In connection with the SUGS Contribution, Regency issued $600 million of 4.50% Senior Notes due 2023 (the "Regency Debt"), the proceeds of which were used by Regency to fund the cash portion of the consideration, as adjusted, and pay certain other expenses or disbursements directly related to the closing of the SUGS Contribution. In connection with the closing of the SUGS Contribution on April 30, 2013, Regency entered into an agreement with PEPL Holdings, a subsidiary of Southern Union, pursuant to which PEPL Holdings provided a guarantee of collection (on a nonrecourse basis to Southern Union) to Regency and Regency Energy Finance Corp. with respect to the payment of the principal amount of the Regency Debt through maturity in 2023. In connection with the completion of the Panhandle Merger, in which PEPL Holdings was merged with and into Panhandle, the guarantee of collection for the Regency Debt was assumed by Panhandle.

NGL Pipeline Regulation

We have interests in NGL pipelines located in Texas and New Mexico. We commenced the interstate transportation of NGLs in 2013, which is subject to the jurisdiction of the FERC under the ICA and the Energy Policy Act of 1992. Under the ICA, tariffs must be just and reasonable and not unduly discriminatory or confer any undue preference. The tariff rates established for interstate services were based on a negotiated agreement; however, the FERC's rate-making methodologies may limit our ability to set rates based on our actual costs, may delay or limit the use of rates that reflect increased costs and may subject us to potentially burdensome and expensive operational, reporting and other requirements. Any of the foregoing could adversely affect our business, revenues and cash flow.

Commitments

In the normal course of our business, we purchase, process and sell natural gas pursuant to long-term contracts and we enter into long-term transportation and storage agreements. Such contracts contain terms that are customary in the industry. We believe that the terms of these agreements are commercially reasonable and will not have a material adverse effect on our financial position or results of operations.

We have certain non-cancelable leases for property and equipment, which require fixed monthly rental payments and expire at various dates through 2056. Rental expense under these operating leases has been included in operating expenses in the accompanying statements of operations and totaled approximately $140 million, $57 million and $26 million for the years ended December 31, 2013, 2012 and 2011, respectively, which include contingent rentals totaling $22 million and $6 million in 2013 and 2012, respectively. During the years ended December 31, 2013 and 2012, approximately $24 million and $4 million, respectively, of rental expense was recovered through related sublease rental income.

Future minimum lease commitments for such leases are:

Years Ending December 31:		
2014	$	80
2015		78
2016		70
2017		66
2018		53
Thereafter		420
Future minimum lease commitments		767
Less: Sublease rental income		(57)
Net future minimum lease commitments	$	710

Our joint venture agreements require that we fund our proportionate share of capital contributions to our unconsolidated affiliates. Such contributions will depend upon our unconsolidated affiliates' capital requirements, such as for funding capital projects or repayment of long-term obligations.

Litigation and Contingencies

We may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business. Natural gas and crude are flammable and combustible. Serious personal injury and significant property damage can arise in connection with their transportation, storage or use. In the ordinary course of business, we are sometimes threatened with or named as a defendant in various lawsuits seeking actual and punitive damages for product liability, personal injury and property damage. We maintain liability insurance with insurers in amounts and with coverage and deductibles management believes are reasonable and prudent, and which are generally accepted in the industry. However, there can be no assurance that the levels of insurance protection currently in effect will continue to be available at reasonable prices or that such levels will remain adequate to protect us from material expenses related to product liability, personal injury or property damage in the future.

Sunoco Litigation

Following the announcement of the Sunoco Merger on April 30, 2012, eight putative class action and derivative complaints were filed in connection with the Sunoco Merger in the Court of Common Pleas of Philadelphia County, Pennsylvania. Each complaint names as defendants the members of Sunoco's board of directors and alleges that they breached their fiduciary duties by negotiating and executing, through an unfair and conflicted process, a merger agreement that provides inadequate consideration and that contains impermissible terms designed to deter alternative bids. Each complaint also names as defendants Sunoco, ETP, ETP GP, ETP LLC, and Sam Acquisition Corporation, alleging that they aided and abetted the breach of fiduciary duties by Sunoco's directors; some of the complaints also name ETE as a defendant on those aiding and abetting claims. In September 2012, all of these lawsuits were settled with no payment obligation on the part of any of the defendants following the filing of Current Reports on Form 8-K that included additional disclosures that were incorporated by reference into the proxy statement related to the Sunoco Merger. Subsequent to the settlement of these cases, the plaintiffs' attorneys sought compensation from Sunoco for attorneys' fees related to their efforts in obtaining these additional disclosures. In January 2013, Sunoco entered into agreements to compensate the plaintiffs' attorneys in the state court actions in the aggregate amount of not more than $950,000 and to compensate the plaintiffs' attorneys in the federal court action in the amount of not more than $250,000. The payment of $950,000 was made in July 2013.

Litigation Relating to the Southern Union Merger

In June 2011, several putative class action lawsuits were filed in the Judicial District Court of Harris County, Texas naming as defendants the members of the Southern Union Board, as well as Southern Union and ETE. The lawsuits were styled *Jaroslawicz v. Southern Union Company, et al.*, Cause No. 2011-37091, in the 333rd Judicial District Court of Harris County, Texas and *Magda v. Southern Union Company, et al.*, Cause No. 2011-37134, in the 11th Judicial District Court of Harris County, Texas. The lawsuits were consolidated into an action styled *In re: Southern Union Company*; Cause No. 2011-37091, in the 333rd Judicial District Court of Harris County, Texas. Plaintiffs allege that the Southern Union directors breached their fiduciary duties to Southern Union's stockholders in connection with the Merger and that Southern Union and ETE aided and abetted the alleged breaches of fiduciary duty. The amended petitions allege that the Merger involves an unfair price and an inadequate sales process, that Southern Union's directors entered into the Merger to benefit themselves personally, including through consulting and noncompete agreements, and that defendants have failed to disclose all material information related to the Merger to Southern Union stockholders. The amended petitions seek injunctive relief, including an injunction of the Merger, and an award of attorneys' and other fees and costs, in addition to other relief. On October 21, 2011, the court denied ETE's October 13, 2011, motion to stay the Texas proceeding in favor of cases pending in the Delaware Court of Chancery.

Also in June 2011, several putative class action lawsuits were filed in the Delaware Court of Chancery naming as defendants the members of the Southern Union Board, as well as Southern Union and ETE. Three of the lawsuits also named Merger Sub as a defendant. These lawsuits are styled: *Southeastern Pennsylvania Transportation Authority, et al. v. Southern Union Company, et al.*, C.A. No. 6615-CS; *KBC Asset Management NV v. Southern Union Company, et al.*, C.A. No. 6622-CS; *LBBW Asset Management Investment GmbH v. Southern Union Company, et al.*, C.A. No. 6627-CS; and *Memo v. Southern Union Company, et al.*, C.A. No. 6639-CS. These cases were consolidated with the following style: *In re Southern Union Co. Shareholder Litigation*, C.A. No. 6615-CS, in the Delaware Court of Chancery. The consolidated complaint asserts similar claims and allegations as the Texas state-court consolidated action. On July 25, 2012, the Delaware plaintiffs filed a notice of voluntary dismissal of all claims without prejudice. In the notice, plaintiffs stated their claims were being dismissed to avoid duplicative litigation and indicated their intent to join the Texas case.

On September 18, 2013, the plaintiff dismissed without prejudice its lawsuit against all defendants.

MTBE Litigation

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 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 also seek natural resource damages, injunctive relief, punitive damages and attorneys' fees.

As of December 31, 2013, Sunoco is a defendant in seven cases, one of which was initiated by the State of New Jersey and two others by the Commonwealth of Puerto Rico with the more recent Puerto Rico action being a companion case alleging damages for additional sites beyond those at issue in the initial Puerto Rico action. Six of these cases are venued in a multidistrict litigation ("MDL") proceeding in a New York federal court. The most recently filed Puerto Rico action is expected to be transferred to the MDL. The New Jersey and Puerto Rico 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.

Fact discovery has concluded with respect to an initial set of fewer than 20 sites each that will be the subject of the first trial phase in the New Jersey case and the initial Puerto Rico case. Insufficient information has been developed about the plaintiffs' legal theories or the facts with respect to statewide natural resource damage claims to provide an analysis of the ultimate potential liability of Sunoco in these matters; however, it is reasonably possible that a loss may be realized. Management believes that an adverse determination with respect to one or more of the MTBE cases could have a significant impact on results of operations during the period in which any said adverse determination occurs, but does not believe that any such adverse determination would have a material adverse effect on the Partnership's consolidated financial position.

Other Litigation and Contingencies

In November 2011, a derivative lawsuit was filed in the Judicial District Court of Harris County, Texas naming as defendants ETP, ETP GP, ETP LLC, the boards of directors of ETP LLC (collectively with ETP GP and ETP LLC, the "ETP Defendants"), certain members of management for ETP and ETE, ETE, and Southern Union. The lawsuit is styled W. J. Garrett Trust v. Bill W. Byrne, et al., Cause No. 2011-71702, in the 157th Judicial District Court of Harris County, Texas. Plaintiffs assert claims for breaches of fiduciary duty, breaches of contractual duties, and acts of bad faith against each of the ETP Defendants and the individual defendants. Plaintiffs also assert claims for aiding and abetting and tortious interference with contract against Southern Union. On October 5, 2012, certain defendants filed a motion for summary judgment with respect to the primary allegations in this action. On December 13, 2012, Plaintiffs filed their opposition to the motion for summary judgment. Defendants filed a reply on December 19, 2012. On December 20, 2012, the court conducted an oral hearing on the motion. Plaintiffs filed a post-hearing sur-reply on January 7, 2013. On January 16, 2013, the Court granted defendants' motion for summary judgment. The parties agreed to settle the matter and executed a memorandum of understanding. On October 4, 2013, the Court approved the settlement and ordered the case dismissed with prejudice.

We or our subsidiaries are a party to various legal proceedings and/or regulatory proceedings incidental to our businesses. For each of these matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies, the likelihood of an unfavorable outcome and the availability of insurance coverage. If we determine that an unfavorable outcome of a particular matter is probable and can be estimated, we accrue the contingent obligation, as well as any expected insurance recoverable amounts related to the contingency. As of December 31, 2013 and 2012, accruals of approximately $46 million and $42 million, respectively, were reflected on our consolidated balance sheets related to these contingent obligations. As new information becomes available, our estimates may change. The impact of these changes may have a significant effect on our results of operations in a single period.

The outcome of these matters cannot be predicted with certainty and there can be no assurance that the outcome of a particular matter will not result in the payment of amounts that have not been accrued for the matter. Furthermore, we may revise accrual amounts prior to resolution of a particular contingency based on changes in facts and circumstances or changes in the expected outcome.

No amounts have been recorded in our December 31, 2013 or 2012 consolidated balance sheets for contingencies and current litigation, other than amounts disclosed herein.

Litigation Related to Incident at JJ's Restaurant. On February 19, 2013, there was a natural gas explosion at JJ's Restaurant located at 910 W. 48th Street in Kansas City, Missouri. Effective September 1, 2013, Laclede Gas Company, a subsidiary of The Laclede Group, Inc. (“Laclede”), assumed any and all liability arising from this incident in ETP’s sale of the assets of MGE to Laclede.

Attorney General of the Commonwealth of Massachusetts v New England Gas Company. On July 7, 2011, the Massachusetts Attorney General (“AG”) filed a regulatory complaint with the MDPU against New England Gas Company with respect to certain environmental cost recoveries. The AG is seeking a refund to New England Gas Company customers for alleged “excessive and imprudently incurred costs” related to legal fees associated with Southern Union’s environmental response activities. In the complaint, the AG requests that the MDPU initiate an investigation into the New England Gas Company’s collection and reconciliation of recoverable environmental costs including: (i) the prudence of any and all legal fees, totaling approximately $19 million, that were charged by the Kasowitz, Benson, Torres & Friedman firm and passed through the recovery mechanism since 2005, the year when a partner in the firm, the Southern Union former Vice Chairman, President and Chief Operating Officer, joined Southern Union’s management team; (ii) the prudence of any and all legal fees that were charged by the Bishop, London & Dodds firm and passed through the recovery mechanism since 2005, the period during which a member of the firm served as Southern Union’s Chief Ethics Officer; and (iii) the propriety and allocation of certain legal fees charged that were passed through the recovery mechanism that the AG contends only qualify for a lesser, 50%, level of recovery. Southern Union has filed its answer denying the allegations and moved to dismiss the complaint, in part on a theory of collateral estoppel. The hearing officer has deferred consideration of Southern Union’s motion to dismiss. The AG’s motion to be reimbursed expert and consultant costs by Southern Union of up to $150,000 was granted. By tariff, these costs are recoverable through rates charged to New England Gas Company customers. The hearing officer previously stayed discovery pending resolution of a dispute concerning the applicability of attorney-client privilege to legal billing invoices. The MDPU issued an interlocutory order on June 24, 2013 that lifted the stay, and discovery has resumed. Southern Union believes it has complied with all applicable requirements regarding its filings for cost recovery and has not recorded any accrued liability; however, Southern Union will continue to assess its potential exposure for such cost recoveries as the matter progresses.

Environmental Matters

Our operations are subject to extensive federal, state and local environmental and safety laws and regulations that require expenditures to ensure compliance, including related to air emissions and wastewater discharges, at operating facilities and for remediation at current and former facilities as well as waste disposal sites. Although we believe our operations are in substantial compliance with applicable environmental laws and regulations, risks of additional costs and liabilities are inherent in the business of transporting, storing, gathering, treating, compressing, blending and processing natural gas, natural gas liquids and other products. As a result, there can be no assurance that significant costs and liabilities will not be incurred. Costs of planning, designing, constructing and operating pipelines, plants and other facilities must incorporate compliance with environmental laws and regulations and safety standards. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, the issuance of injunctions and the filing of federally authorized citizen suits. Contingent losses related to all significant known environmental matters have been accrued and/or separately disclosed. However, we may revise accrual amounts prior to resolution of a particular contingency based on changes in facts and circumstances or changes in the expected outcome.

Environmental exposures and liabilities are difficult to assess and estimate due to unknown factors such as the magnitude of possible contamination, the timing and extent of remediation, the determination of our liability in proportion to other parties, improvements in cleanup technologies and the extent to which environmental laws and regulations may change in the future.

Although environmental costs may have a significant impact on the results of operations for any single period, we believe that such costs will not have a material adverse effect on our financial position.

Based on information available at this time and reviews undertaken to identify potential exposure, we believe the amount reserved for environmental matters is adequate to cover the potential exposure for cleanup costs.

Environmental Remediation

Our subsidiaries are responsible for environmental remediation at certain sites, including the following:

- Certain of our interstate pipelines conduct soil and groundwater remediation related to contamination from past uses of PCBs. PCB assessments are ongoing and, in some cases, our subsidiaries could potentially be held responsible for contamination caused by other parties.
- Certain gathering and processing systems are responsible for soil and groundwater remediation related to releases of hydrocarbons.
- Southern Union’s distribution operations are responsible for soil and groundwater remediation at certain sites related to manufactured gas plants (“MGPs”) and may also be responsible for the removal of old MGP structures.
- Currently operating Sunoco retail sites.
- Legacy sites related to Sunoco, 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.
- Sunoco is potentially subject to joint and several liability for the costs of remediation at sites at which it has been identified as a potentially responsible party (“PRP”). As of December 31, 2013, Sunoco had been named as a PRP at 40 identified or potentially identifiable as “Superfund” sites under federal and/or comparable state law. Sunoco is usually one of a number of companies identified as a PRP at a site. Sunoco has reviewed the nature and extent of its involvement at each site and other relevant circumstances and, based upon Sunoco’s purported nexus to the sites, believes that its potential liability associated with such sites will not be significant.

To the extent estimable, expected remediation costs are included in the amounts recorded for environmental matters in our consolidated balance sheets. In some circumstances, future costs cannot be reasonably estimated because remediation activities are undertaken as claims are made by customers and former customers. To the extent that an environmental remediation obligation is recorded by a subsidiary that applies regulatory accounting policies, amounts that are expected to be recoverable through tariffs or rates are recorded as regulatory assets on our consolidated balance sheets.

The table below reflects the amounts of accrued liabilities recorded in our consolidated balance sheets related to environmental matters that are considered to be probable and reasonably estimable. Except for matters discussed above, we do not have any material environmental matters assessed as reasonably possible that would require disclosure in our consolidated financial statements.

	December 31,	
	2013	2012
Current	$ 45	$ 46
Non-current	350	165
Total environmental liabilities	$ 395	$ 211

In 2013, we have established a wholly-owned captive insurance company to bear certain risks associated with environmental obligations related to certain sites that are no longer operating. The premiums paid to the captive insurance company include estimates for environmental claims that have been incurred but not reported, based on an actuarially determined fully developed claims expense estimate. In such cases, we accrue losses attributable to unasserted claims based on the discounted estimates that are used to develop the premiums paid to the captive insurance company.

During the years ended December 31, 2013 and 2012, Sunoco had $36 million and $12 million, respectively, of expenditures related to environmental cleanup programs.

The EPA’s Spill Prevention, Control and Countermeasures program regulations were recently modified and impose additional requirements on many of our facilities. We expect to expend resources on tank integrity testing and any associated corrective actions as well as potential upgrades to containment structures to comply with the new rules. Costs associated with tank integrity testing and resulting corrective actions cannot be reasonably estimated at this time, but we believe such costs will not have a material adverse effect on our financial position, results of operations or cash flows.

On August 20, 2010, the EPA published new regulations under the federal Clean Air Act ("CAA") to control emissions of hazardous air pollutants from existing stationary reciprocal internal combustion engines. The rule will require us to undertake certain expenditures and activities, likely including purchasing and installing emissions control equipment. In response to an industry group legal challenge to portions of the rule in the U.S. Court of Appeals for the D.C. Circuit and a Petition for Administrative Reconsideration to the EPA, on March 9, 2011, the EPA issued a new proposed rule and direct final rule effective on May 9, 2011 to clarify compliance requirements related to operation and maintenance procedures for continuous parametric monitoring systems. If no further changes to the standard are made as a result of comments to the proposed rule, we would not expect that the cost to comply with the rule's requirements will have a material adverse effect on our financial condition or results of operations. Compliance with the final rule was required by October 2013, and the Partnership believes it is in compliance.

On June 29, 2011, the EPA finalized a rule under the CAA that revised the new source performance standards for manufacturers, owners and operators of new, modified and reconstructed stationary internal combustion engines. The rule became effective on August 29, 2011. The rule modifications may require us to undertake significant expenditures, including expenditures for purchasing, installing, monitoring and maintaining emissions control equipment, if we replace equipment or expand existing facilities in the future. At this point, we are not able to predict the cost to comply with the rule's requirements, because the rule applies only to changes we might make in the future.

Our pipeline operations are subject to regulation by the DOT under the PHMSA, pursuant to which the PHMSA has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. Moreover, the PHMSA, through the Office of Pipeline Safety, has promulgated a rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the rule refers to as "high consequence areas." Activities under these integrity management programs involve the performance of internal pipeline inspections, pressure testing or other effective means to assess the integrity of these regulated pipeline segments, and the regulations require prompt action to address integrity issues raised by the assessment and analysis. 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 future capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines; however, no estimate can be made at this time of the likely range of such expenditures.

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

11. PRICE RISK MANAGEMENT ASSETS AND LIABILITIES:

Commodity Price Risk

We are exposed to market risks related to the volatility of commodity prices. To manage the impact of volatility from these prices, we utilize various exchange-traded and OTC commodity financial instrument contracts. These contracts consist primarily of futures, swaps and options and are recorded at fair value in our consolidated balance sheets.

We inject and hold natural gas in our Bammel storage facility to take advantage of contango markets (i.e., 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 into 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 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. 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 price 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 through either mark-to-market adjustments or the physical withdraw of natural gas.

We are also exposed to market risk on natural gas we retain for fees in our intrastate transportation and storage segment and operational gas sales on our interstate transportation and storage segment. We use financial derivatives to hedge the sales price of this gas, including futures, swaps and options. Certain contracts that qualify for hedge accounting are designated as cash flow hedges of the forecasted sale of natural gas. The change in value, to the extent the contracts are effective, remains in AOCI 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.

We are also exposed to commodity price risk on NGLs and residue gas we retain for fees in our midstream segment whereby our subsidiaries generally 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 for the residue gas and NGLs. We use NGL and crude derivative swap contracts to hedge forecasted sales of NGL and condensate equity volumes. Certain contracts that qualify for hedge accounting are accounted for as cash flow hedges. The change in value, to the extent the contracts are effective, remains in AOCI 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.

We may use derivatives in our NGL transportation and services segment to manage our storage facilities and the purchase and sale of purity NGLs.

Sunoco Logistics utilizes derivatives such as swaps, futures and other derivative instruments to mitigate the risk associated with market movements in the price of refined products and NGLs. These derivative contracts act as a hedging mechanism against the volatility of prices by allowing Sunoco Logistics to transfer this price risk to counterparties who are able and willing to bear it. Since the first quarter 2013, Sunoco Logistics has not designated any of its derivative contracts as hedges for accounting purposes. Therefore, all realized and unrealized gains and losses from these derivative contracts are recognized in the consolidated statements of operations during the current period.

Our trading activities include the use of financial commodity derivatives to take advantage of market opportunities. These trading activities are a complement to our transportation and storage segment's operations and are netted in cost of products sold in our consolidated statements of operations. Additionally, we also have trading activities related to power and natural gas in our all other segment which are also netted in cost of products sold. As a result of our trading activities and the use of derivative financial instruments in our transportation and storage segment, the degree of earnings volatility that can occur may be significant, favorably or unfavorably, from period to period. We attempt to manage this volatility through the use of daily position and profit and loss reports provided to our risk oversight committee, which includes members of senior management, and the limits and authorizations set forth in our commodity risk management policy.

Derivatives are utilized in our all other segment in order to mitigate price volatility and manage fixed price exposure incurred from contractual obligations. We attempt to maintain balanced positions in our marketing activities to protect against volatility in the energy commodities markets; however, net unbalanced positions can exist.

The following table details our outstanding commodity-related derivatives:

	December 31, 2013		December 31, 2012	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark-to-Market Derivatives				
(Trading)				
Natural Gas (MMBtu):				
Fixed Swaps/Futures	9,457,500	2014-2019	—	—
Basis Swaps IFERC/NYMEX[1]	(487,500)	2014-2017	(30,980,000)	2013-2014
Swing Swaps	1,937,500	2014-2016	—	—
Power (Megawatt):				
Forwards	351,050	2014	19,650	2013
Futures	(772,476)	2014	(1,509,300)	2013
Options – Puts	(52,800)	2014	—	—
Options – Calls	103,200	2014	1,656,400	2013
Crude (Bbls) – Futures	103,000	2014	—	—
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	570,000	2014	150,000	2013
Swing Swaps IFERC	(9,690,000)	2014-2016	(83,292,500)	2013
Fixed Swaps/Futures	(8,195,000)	2014-2015	27,077,500	2013
Forward Physical Contracts	5,668,559	2014-2015	11,689,855	2013-2014
Natural Gas Liquid (Bbls) – Forwards/Swaps	(280,000)	2014	(30,000)	2013
Refined Products (Bbls) – Futures	(1,133,600)	2014	(666,000)	2013
Fair Value Hedging Derivatives				
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	(7,352,500)	2014	(18,655,000)	2013
Fixed Swaps/Futures	(50,530,000)	2014	(44,272,500)	2013
Hedged Item – Inventory	50,530,000	2014	44,272,500	2013
Cash Flow Hedging Derivatives				
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	(1,825,000)	2014	—	—
Fixed Swaps/Futures	(12,775,000)	2014	(8,212,500)	2013
Natural Gas Liquid (Bbls) – Forwards/Swaps	(780,000)	2014	(930,000)	2013
Refined Products (Bbls) – Futures	—	—	(98,000)	2013
Crude (Bbls) – Futures	(30,000)	2014	—	—

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

We expect gains of $4 million related to commodity derivatives to be reclassified into earnings over the next 12 months related to amounts currently reported in AOCI. The amount ultimately realized, however, will differ as commodity prices change and the underlying physical transaction occurs.

Interest Rate Risk

We are exposed to market risk for changes in interest rates. To maintain a cost effective capital structure, we borrow funds using a mix of fixed rate debt and variable rate debt. We also manage our interest rate exposure by utilizing interest rate swaps to achieve a desired mix of fixed and variable rate debt. We also utilize forward starting interest rate swaps to lock in the rate on a portion of our anticipated debt issuances.

The following table summarizes our interest rate swaps outstanding, none of which were designated as hedges for accounting purposes:

			Notional Amount Outstanding	
Entity	Term	Type[1]	December 31, 2013	December 31, 2012
ETP	July 2013[2]	Forward-starting to pay a fixed rate of 4.03% and receive a floating rate	$ —	$ 400
ETP	July 2014[2]	Forward-starting to pay a fixed rate of 4.25% and receive a floating rate	400	400
ETP	July 2018	Pay a floating rate plus a spread of 4.17% and receive a fixed rate of 6.70%	600	600
ETP	June 2021	Pay a floating rate plus a spread of 2.17% and receive a fixed rate of 4.65%	400	—
ETP	February 2023	Pay a floating rate plus a spread of 1.32% and receive a fixed rate of 3.60%	400	—
Southern Union[3]	November 2016	Pay a fixed rate of 2.97% and receive a floating rate	—	75
Southern Union[3]	November 2021	Pay a fixed rate of 3.801% and receive a floating rate	275	450

(1) Floating rates are based on 3-month LIBOR.

(2) Represents the effective date. During the year ended December 31, 2013, we settled $400 million of ETP's forward-starting interest rate swaps that had an effective date of July 2013. These forward starting swaps have a term of 10 years with a mandatory termination date the same as the effective date.

(3) In connection with the Panhandle Merger, Southern Union's interest rate swaps outstanding were assumed by Panhandle.

Credit Risk

Credit risk refers to the risk that a counterparty may default on its contractual obligations resulting in a loss to the Partnership. Credit policies have been approved and implemented to govern the Partnership's portfolio of counterparties with the objective of mitigating credit losses. These policies establish guidelines, controls and limits to manage credit risk within approved tolerances by mandating an appropriate evaluation of the financial condition of existing and potential counterparties, monitoring agency credit ratings, and by implementing credit practices that limit exposure according to the risk profiles of the counterparties. Furthermore, the Partnership may at times require collateral under certain circumstances to mitigate credit risk as necessary. We also implement the use of industry standard commercial agreements which allow for the netting of positive and negative exposures associated with transactions executed under a single commercial agreement. Additionally, we utilize master netting agreements to offset credit exposure across multiple commercial agreements with a single counterparty or affiliated group of counterparties.

The Partnership's counterparties consist of a diverse portfolio of customers across the energy industry, including petrochemical companies, commercial and industrials, oil and gas producers, municipalities, utilities and midstream companies. Our overall exposure may be affected positively or negatively by macroeconomic or regulatory changes that could impact our counterparties to one extent or another. Currently, management does not anticipate a material adverse effect in our financial position or results of operations as a consequence of counterparty non-performance.

We have maintenance margin deposits with certain counterparties in the OTC market, primarily independent system operators, and with clearing brokers. Payments on margin deposits are required when the value of a derivative exceeds our pre-established credit limit with the counterparty. Margin deposits are returned to us on or about the settlement date for non-exchange traded derivatives, and we exchange margin calls on a daily basis for exchange traded transactions. Since the margin calls are made daily with the exchange brokers, the fair value of the financial derivative instruments are deemed current and netted in deposits paid to vendors within other current assets in the consolidated balance sheets.

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 sheets and recognized in net income or other comprehensive income.

Derivative Summary

The following table provides a summary of our derivative assets and liabilities:

	Fair Value of Derivative Instruments			
	Asset Derivatives		Liability Derivatives	
	December 31, 2013	December 31, 2012	December 31, 2013	December 31, 2012
Derivatives designated as hedging instruments:				
Commodity derivatives (margin deposits)	$ 3	$ 8	$ (18)	$ (10)
	3	8	(18)	(10)
Derivatives not designated as hedging instruments:				
Commodity derivatives (margin deposits)	227	110	(209)	(116)
Commodity derivatives	39	33	(38)	(34)
Current assets held for sale	—	1	—	—
Non-current assets held for sale	—	1	—	—
Current liabilities held for sale	—	—	—	(9)
Interest rate derivatives	47	55	(95)	(223)
	313	200	(342)	(382)
Total derivatives	$ 316	$ 208	$ (360)	$ (392)

In addition to the above derivatives, $7 million in option premiums were included in price risk management liabilities as of December 31, 2012.

The following table presents the fair value of our recognized derivative assets and liabilities on a gross basis and amounts offset on the consolidated balance sheets that are subject to enforceable master netting arrangements or similar arrangements:

		Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	December 31, 2013	December 31, 2012	December 31, 2013	December 31, 2012
Derivatives in offsetting agreements:					
OTC contracts	Price risk management assets (liabilities)	$ 41	$ 28	$ (38)	$ (27)
Broker cleared derivative contracts	Other current assets (liabilities)	265	150	(318)	(228)
		306	178	(356)	(255)
Offsetting agreements:					
Collateral paid to OTC counterparties	Other current assets	—	—	—	2
Counterparty netting	Price risk management assets (liabilities)	(36)	(25)	36	25
Payments on margin deposit	Other current assets	(1)	—	55	59
		(37)	(25)	91	86
Net derivatives with offsetting agreements		269	153	(265)	(169)
Derivatives without offsetting agreements		47	55	(95)	(223)
Total derivatives		$ 316	$ 208	$ (360)	$ (392)

We disclose the non-exchange traded financial derivative instruments as price risk management assets and liabilities on our consolidated balance sheets at fair value with amounts classified as either current or long-term depending on the anticipated settlement date.

The following tables summarize the amounts recognized with respect to our derivative financial instruments:

	Change in Value Recognized in OCI on Derivatives (Effective Portion)		
	Years Ended December 31,		
	2013	2012	2011
Derivatives in cash flow hedging relationships:			
Commodity derivatives	$ (1)	$ 8	$ 19
Total	$ (1)	$ 8	$ 19

	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)		
		Years Ended December 31,		
		2013	2012	2011
Derivatives in cash flow hedging relationships:				
Commodity derivatives	Cost of products sold	$ 4	$ 14	$ 38
Total		$ 4	$ 14	$ 38

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income Representing Hedge Ineffectiveness and Amount Excluded from the Assessment of Effectiveness		
		Years Ended December 31,		
		2013	2012	2011
Derivatives in fair value hedging relationships (including hedged item):				
Commodity derivatives	Cost of products sold	$ 8	$ 54	$ 34
Total		$ 8	$ 54	$ 34

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income on Derivatives		
		Years Ended December 31,		
		2013	2012	2011
Derivatives not designated as hedging instruments:				
Commodity derivatives – Trading	Cost of products sold	$ (11)	$ (7)	$ (30)
Commodity derivatives – Non-trading	Cost of products sold	(12)	(15)	9
Commodity contracts – Non-trading	Deferred gas purchases	(3)	(26)	—
Interest rate derivatives	Gains (losses) on interest rate derivatives	44	(4)	(77)
Total		$ 18	$ (52)	$ (98)

12. RETIREMENT BENEFITS:

Savings and Profit Sharing Plans

We and our subsidiaries sponsor defined contribution savings and profit sharing plans, which collectively cover virtually all employees. Employer matching contributions are calculated using a formula based on employee contributions. We and our subsidiaries made matching contributions of $38 million, $21 million and $11 million to these 401(k) savings plans for the years ended December 31, 2013, 2012 and 2011, respectively.

Pension and Other Postretirement Benefit Plans

Southern Union

Southern Union has funded non-contributory defined benefit pension plans that cover substantially all employees of Southern Union's distribution operations. Normal retirement age is 65, but certain plan provisions allow for earlier retirement. Pension benefits are calculated under formulas principally based on average earnings and length of service for salaried and non-union employees and average earnings and length of service or negotiated non-wage based formulas for union employees.

The 2012 postretirement benefits expense for Southern Union reflects the impact of curtailment accounting as postretirement benefits for all active participants who did not meet certain criteria were eliminated. Southern Union previously had postretirement health care and life insurance plans that covered substantially of its distribution and transportation and storage operations employees as well as all corporate employees. The health care plans generally provide for cost sharing between Southern Union and its retirees in the form of retiree contributions, deductibles, coinsurance, and a fixed cost cap on the amount Southern Union pays annually to provide future retiree health care coverage under certain of these plans.

Sunoco

Sunoco has both funded and unfunded noncontributory defined benefit pension plans. Sunoco also has plans which provide health care benefits for substantially all of its current retirees ("postretirement benefit plans"). The postretirement benefit plans are unfunded and the costs are shared by Sunoco and its retirees. Prior to the Sunoco Merger on October 5, 2012, pension benefits under Sunoco's defined benefit plans were frozen for most of the participants in these plans at which time Sunoco instituted a discretionary profit-sharing contribution on behalf of these employees in its defined contribution plan. Postretirement medical benefits were also phased down or eliminated for all employees retiring after July 1, 2010. Sunoco has established a trust for its postretirement benefit liabilities by making a tax-deductible contribution of approximately $200 million and restructuring the retiree medical plan to eliminate Sunoco's liability beyond this funded amount. The retiree medical plan change eliminated substantially all of Sunoco's future exposure to variances between actual results and assumptions used to estimate retiree medical plan obligations.

Obligations and Funded Status

Pension and other postretirement benefit liabilities are accrued on an actuarial basis during the years an employee provides services. The following table contains information at the dates indicated about the obligations and funded status of pension and other postretirement plans on a combined basis:

	December 31, 2013			December 31, 2012	
	Pension Benefits				
	Funded Plans	Unfunded Plans	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Change in benefit obligation:					
Benefit obligation at beginning of period	$ 1,117	$ 78	$ 296	$ 1,257	$ 359
Service cost	3	—	—	3	1
Interest cost	33	2	6	15	3
Amendments	—	—	2	—	17
Benefits paid, net	(99)	(16)	(26)	(71)	(8)
Curtailments	—	—	—	—	(80)
Actuarial (gain) loss and other	(74)	(3)	(14)	(9)	4
Settlements	(95)	—	—	—	—
Dispositions	(253)	—	(41)	—	—
Benefit obligation at end of period	632	61	223	1,195	296
Change in plan assets:					
Fair value of plan assets at beginning of period	906	—	312	941	306
Return on plan assets and other	43	—	17	22	5
Employer contributions	—	—	8	14	9
Benefits paid, net	(99)	—	(26)	(71)	(8)
Settlements	(95)	—	—	—	—
Dispositions	(155)	—	(27)	—	—
Fair value of plan assets at end of period	600	—	284	906	312
Amount underfunded (overfunded) at end of period	$ 32	$ 61	$ (61)	$ 289	$ (16)
Amounts recognized in the consolidated balance sheets consist of:					
Non-current assets	$ —	$ —	$ 86	$ —	$ 59
Current liabilities	—	(9)	(2)	(15)	(2)
Non-current liabilities	(32)	(52)	(23)	(274)	(41)
	$ (32)	$ (61)	$ 61	$ (289)	$ 16
Amounts recognized in accumulated other comprehensive loss (pre-tax basis) consist of:					
Net actuarial gain	$ (86)	$ (4)	$ (25)	$ (1)	$ (1)
Prior service cost	—	—	18	—	16
	$ (86)	$ (4)	$ (7)	$ (1)	$ 15

The following table summarizes information at the dates indicated for plans with an accumulated benefit obligation in excess of plan assets:

	December 31, 2013			December 31, 2012	
	Pension Benefits				
	Funded Plans	Unfunded Plans	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Projected benefit obligation	$ 632	$ 61	N/A	$ 1,195	N/A
Accumulated benefit obligation	632	61	223	1,179	$ 225
Fair value of plan assets	600	—	284	906	185

Components of Net Periodic Benefit Cost

	December 31, 2013		December 31, 2012	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Net Periodic Benefit Cost:				
Service cost	$ 3	$ —	$ 3	$ 1
Interest cost	35	6	15	3
Expected return on plan assets	(54)	(9)	(21)	(5)
Prior service cost amortization	—	1	—	—
Actuarial loss amortization	2	—	—	—
Special termination benefits charge	—	—	2	—
Curtailment recognition[(1)]	—	—	—	(15)
Settlements	(2)	—	—	—
	(16)	(2)	(1)	(16)
Regulatory adjustment[(2)]	5	—	9	2
Net periodic benefit cost	$ (11)	$ (2)	$ 8	$ (14)

(1) Subsequent to the Southern Union Merger, Southern Union amended certain of its other postretirement employee benefit plans, which prospectively restrict participation in the plans for the impacted active employees. The plan amendments resulted in the plans becoming currently over-funded and, accordingly, Southern Union recorded a pre-tax curtailment gain of $75 million. Such gain was offset by establishment of a non-current refund liability in the amount of $60 million. As such, the net curtailment gain recognition was $15 million.

(2) Southern Union has historically recovered certain qualified pension benefit plan and other postretirement benefit plan costs through rates charged to utility customers in its distribution operations. Certain utility commissions require that the recovery of these costs be based on the Employee Retirement Income Security Act of 1974, as amended, or other utility commission specific guidelines. The difference between these regulatory-based amounts and the periodic benefit cost calculated pursuant to GAAP is deferred as a regulatory asset or liability and amortized to expense over periods in which this difference will be recovered in rates, as promulgated by the applicable utility commission.

Assumptions

The weighted-average assumptions used in determining benefit obligations at the dates indicated are shown in the table below:

	December 31, 2013		December 31, 2012	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Discount rate	4.65%	2.33%	3.41%	2.39%
Rate of compensation increase	N/A	N/A	3.17%	N/A

The weighted-average assumptions used in determining net periodic benefit cost for the periods presented are shown in the table below:

	December 31, 2013		December 31, 2012	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Discount rate	3.50%	2.68%	2.37%	2.43%
Expected return on assets:				
Tax exempt accounts	7.50%	6.95%	7.63%	7.00%
Taxable accounts	N/A	4.42%	N/A	4.50%
Rate of compensation increase	N/A	N/A	3.02%	N/A

The long-term expected rate of return on plan assets was estimated based on a variety of factors including the historical investment return achieved over a long-term period, the targeted allocation of plan assets and expectations concerning future returns in the marketplace for both equity and fixed income securities. Current market factors such as inflation and interest rates are evaluated before long-term market assumptions are determined. Peer data and historical returns are reviewed to ensure reasonableness and appropriateness.

The assumed health care cost trend rates used to measure the expected cost of benefits covered by Southern Union and Sunoco's other postretirement benefit plans are shown in the table below:

	December 31,	
	2013	2012
Health care cost trend rate assumed for next year	7.57%	7.78%
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	5.42%	5.32%
Year that the rate reaches the ultimate trend rate	2018	2018

Changes in the health care cost trend rate assumptions are not expected to have a significant impact on postretirement benefits.

Plan Assets

For the Southern Union plans, the overall investment strategy is to maintain an appropriate balance of actively managed investments with the objective of optimizing longer-term returns while maintaining a high standard of portfolio quality and achieving proper diversification. To achieve diversity within its pension plan asset portfolio, Southern Union has targeted the following asset allocations: equity of 25% to 70%, fixed income of 15% to 35%, alternative assets of 10% to 35% and cash of 0% to 10%. To achieve diversity within its other postretirement plan asset portfolio, Southern Union has targeted the following asset allocations: equity of 25% to 35%, fixed income of 65% to 75% and cash and cash equivalents of 0% to 10%.

The investment strategy of Sunoco funded defined benefit plans is to achieve consistent positive returns, after adjusting for inflation, and to maximize long-term total return within prudent levels of risk through a combination of income and capital appreciation. The objective of this strategy is to reduce the volatility of investment returns, maintain a sufficient funded status of the plans and limit required contributions. Sunoco has targeted the following asset allocations: equity of 35%, fixed income of 55%, and private equity investments of 10%. Sunoco anticipates future shifts in targeted asset allocation from equity securities to fixed income securities if funding levels improve due to asset performance or Sunoco contributions.

The fair value of the pension plan assets by asset category at the dates indicated is as follows:

	Fair Value as of December 31, 2013	Fair Value Measurements at December 31, 2013 Using Fair Value Hierarchy		
		Level 1	Level 2	Level 3
Asset Category:				
Cash and cash equivalents	$ 12	$ 12	$ —	$ —
Mutual funds[1]	368	—	281	87
Fixed income securities	220	—	220	—
Total	$ 600	$ 12	$ 501	$ 87

(1) Primarily comprised of approximately 66% equities, 10% fixed income securities, and 24% in other investments as of December 31, 2013.

	Fair Value as of December 31, 2012	Fair Value Measurements at December 31, 2012 Using Fair Value Hierarchy		
		Level 1	Level 2	Level 3
Asset Category:				
Cash and cash equivalents	$ 25	$ 25	$ —	$ —
Mutual funds[1]	516	—	433	83
Fixed income securities	354	—	354	—
Multi-strategy hedge funds[2]	11	—	11	—
Total	$ 906	$ 25	$ 798	$ 83

(1) Primarily comprised of approximately 36% equities, 54% fixed income securities, and 10% in other investments as of December 31, 2012.

(2) Primarily includes hedge funds that invest in multiple strategies, including relative value, opportunistic/macro, long/short equities, merger arbitrage/event driven, credit, and short selling strategies, to generate long-term capital appreciation through a portfolio having a diversified risk profile with relatively low volatility and a low correlation with traditional equity and fixed-income markets. These investments can generally be redeemed effective as of the last day of a calendar quarter at the net asset value per share of the investment with approximately 65 days prior written notice.

The fair value of other postretirement plan assets by asset category at the dates indicated is as follows:

	Fair Value as of December 31, 2013	Fair Value Measurements at December 31, 2013 Using Fair Value Hierarchy		
		Level 1	Level 2	Level 3
Asset Category:				
Cash and Cash Equivalents	$ 10	$ 10	$ —	$ —
Mutual funds[1]	130	112	18	—
Fixed income securities	144	—	144	—
Total	$ 284	$ 122	$ 162	$ —

(1) Primarily comprised of approximately 41% equities, 48% fixed income securities, 6% cash, and 5% in other investments as of December 31, 2013.

	Fair Value as of December 31, 2012	Fair Value Measurements at December 31, 2012 Using Fair Value Hierarchy		
		Level 1	Level 2	Level 3
Asset Category:				
Cash and Cash Equivalents	$ 7	$ 7	$ —	$ —
Mutual funds[(1)]	147	126	21	—
Fixed income securities	158	—	158	—
Total	$ 312	$ 133	$ 179	$ —

(1) Primarily comprised of approximately 19% equities, 74% fixed income securities, 4% cash, and 3% in other investments as of December 31, 2012.

The Level 1 plan assets are valued based on active market quotes. The Level 2 plan assets are valued based on the net asset value per share (or its equivalent) of the investments, which was not determinable through publicly published sources but was calculated consistent with authoritative accounting guidelines. See Note 2 for information related to the framework used to measure the fair value of its pension and other postretirement plan assets.

Contributions

We expect to contribute approximately $23 million to pension plans and approximately $18 million to other postretirement plans in 2014. The cost of the plans are funded in accordance with federal regulations, not to exceed the amounts deductible for income tax purposes.

Benefit Payments

Southern Union and Sunoco's estimate of expected benefit payments, which reflect expected future service, as appropriate, in each of the next five years and in the aggregate for the five years thereafter are shown in the table below:

Years	Pension Benefits		Other Postretirement Benefits (Gross, Before Medicare Part D)
	Funded Plans	Unfunded Plans	
2014	$ 82	$ 9	$ 31
2015	77	9	29
2016	67	8	28
2017	61	7	26
2018	56	7	24
2019 – 2023	220	23	87

The Medicare Prescription Drug Act provides for a prescription drug benefit under Medicare ("Medicare Part D") as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a prescription drug benefit that is at least actuarially equivalent to Medicare Part D.

Southern Union does not expect to receive any Medicare Part D subsidies in any future periods.

13. RELATED PARTY TRANSACTIONS:

ETE has agreements with subsidiaries to provide or receive various general and administrative services. ETE pays us to provide services on its behalf and on behalf of other subsidiaries of ETE, which includes the reimbursement of various general and administrative services for expenses incurred by us on behalf of Regency.

In the ordinary course of business, we provide Regency with certain natural gas and NGLs sales and transportation services and compression equipment, and Regency provides us with certain contract compression services. These related party transactions are generally based on transactions made at market-related rates.

Sunoco Logistics has an agreement with PES relating to the Fort Mifflin Terminal Complex. Under this agreement, PES will deliver an average of 300,000 Bbls/d of crude oil and refined products per contract year at the Fort Mifflin facility. PES does not have exclusive use of the Fort Mifflin Terminal Complex; however, Sunoco Logistics is obligated to provide the necessary tanks, marine docks and pipelines for PES to meet its minimum requirements under the agreement. Sunoco Logistics entered into a ten-year agreement to provide terminalling services to PES in September 2012.

In September 2012, Sunoco assigned its lease for the use of Sunoco Logistics' inter-refinery pipelines between the Philadelphia and Marcus Hook refineries to PES. Under the 20-year lease agreement which expires in February 2022, PES leases the inter-refinery pipelines for an annual fee which escalates at 1.67% each January 1 for the term of the agreement. The lease agreement also requires PES to reimburse Sunoco Logistics for any non-routine maintenance expenditures, as defined, incurred during the term of the agreement. There were no material reimbursements under this agreement during the periods presented.

In connection with the acquisition of the Marcus Hook Facility, Sunoco Logistics assumed an agreement to provide butane storage and terminal services to PES at the facility. The 10 year agreement extends through September 2022.

Sunoco Logistics has agreements with PES whereby PES purchases crude oil, at market-based rates, for delivery to Sunoco Logistics' Fort Mifflin and Eagle Point terminal facilities. These agreements contain minimum volume commitments and extend through 2014.

The renegotiated terms of the agreements with PES provide PES with the option to purchase the Fort Mifflin and Belmont terminals if certain triggering events occur, including a sale of substantially all of the assets or operations of the Philadelphia refinery, an initial public offering or a public debt filing of more than $200 million. The purchase price for each facility would be established based on a fair value amount determined by designated third parties.

The following table summarizes the affiliated revenues on our consolidated statements of operations:

	Years Ended December 31,		
	2013	2012	2011
Affiliated revenues	$ 1,550	$ 173	$ 690

The following table summarizes the related company balances on our consolidated balance sheets:

	December 31,	
	2013	2012
Accounts receivable from related companies:		
ETE	$ 18	$ 16
Regency	53	10
PES	7	60
FGT	29	2
Eastern Gulf	24	—
Other	34	6
Total accounts receivable from related companies:	$ 165	$ 94
Accounts payable to related companies:		
ETE	$ 8	$ 7
Regency	24	2
PES	—	13
FGT	8	—
Other	5	2
Total accounts payable to related companies:	$ 45	$ 24

14. REPORTABLE SEGMENTS:

As a result of the Sunoco Merger and Holdco Transaction, our reportable segments were re-evaluated and changed in 2012. Our financial statements currently reflect the following reportable segments, which conduct their business exclusively in the United States, as follows:

- intrastate transportation and storage;

- interstate transportation and storage;
- midstream;
- NGL transportation and services;
- investment in Sunoco Logistics;
- retail marketing; and
- all other.

During the fourth quarter 2013, management realigned the composition of our reportable segments, and as a result, our natural gas marketing operations are now aggregated into the “all other” segment. These operations were previously reported in the midstream segment. Based on this change in our segment presentation, we have recast the presentation of our segment results for the prior years to be consistent with the current year presentation.

Intersegment and intrasegment transactions are generally based on transactions made at market-related rates. Consolidated revenues and expenses reflect the elimination of all material intercompany transactions.

Revenues from our intrastate transportation and storage segment are primarily reflected in natural gas sales and gathering, transportation and other fees. Revenues from our interstate transportation and storage segment are primarily reflected in gathering, transportation and other fees. Revenues from our midstream segment are primarily reflected in natural gas sales, NGL sales and gathering, transportation and other fees. Revenues from our NGL transportation and services segment are primarily reflected in NGL sales and gathering, transportation and other fees. Revenues from our investment in Sunoco Logistics segment are primarily reflected in crude sales. Revenues from our retail marketing segment are primarily reflected in refined product sales.

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 include unrealized gains and losses on commodity derivatives and inventory fair value adjustments (excluding lower of cost or market adjustments). Segment Adjusted EBITDA reflects amounts for unconsolidated affiliates based on the Partnership’s proportionate ownership.

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The following tables present the financial information by segment:

	Years Ended December 31,		
	2013	2012	2011
Revenues:			
Intrastate transportation and storage:			
Revenues from external customers	$ 2,250	$ 2,012	$ 2,398
Intersegment revenues	202	179	276
	2,452	2,191	2,674
Interstate transportation and storage:			
Revenues from external customers	1,270	1,109	447
Intersegment revenues	39	—	—
	1,309	1,109	447
Midstream:			
Revenues from external customers	1,307	1,757	1,082
Intersegment revenues	942	196	401
	2,249	1,953	1,483
NGL transportation and services:			
Revenues from external customers	2,063	619	363
Intersegment revenues	64	31	34
	2,127	650	397
Investment in Sunoco Logistics:			
Revenues from external customers	16,480	3,109	—
Intersegment revenues	159	80	—
	16,639	3,189	—
Retail marketing:			
Revenues from external customers	21,004	5,926	—
Intersegment revenues	8	—	—
	21,012	5,926	—
All other:			
Revenues from external customers	1,965	1,170	2,509
Intersegment revenues	402	385	379
	2,367	1,555	2,888
Eliminations	(1,816)	(871)	(1,090)
Total revenues	$ 46,339	$ 15,702	$ 6,799

	Years Ended December 31,		
	2013	2012	2011
Cost of products sold:			
Intrastate transportation and storage	$ 1,737	$ 1,394	$ 1,774
Midstream	1,579	1,273	988
NGL transportation and services	1,655	361	218
Investment in Sunoco Logistics	15,574	2,885	—
Retail marketing	20,150	5,757	—
All other	2,309	1,496	2,274
Eliminations	(1,800)	(900)	(1,079)
Total cost of products sold	$ 41,204	$ 12,266	$ 4,175

	Years Ended December 31,		
	2013	2012	2011
Depreciation and amortization:			
Intrastate transportation and storage	$ 122	$ 122	$ 120
Interstate transportation and storage	244	209	81
Midstream	172	168	85
NGL transportation and services	91	53	32
Investment in Sunoco Logistics	265	63	—
Retail marketing	114	28	—
All other	24	13	87
Total depreciation and amortization	$ 1,032	$ 656	$ 405

	Years Ended December 31,		
	2013	2012	2011
Equity in earnings (losses) of unconsolidated affiliates:			
Intrastate transportation and storage	$ —	$ 4	$ 2
Interstate transportation and storage	142	120	24
Midstream	—	(9)	—
NGL transportation and services	(2)	2	—
Investment in Sunoco Logistics	18	5	—
Retail marketing	2	1	—
All other	12	19	—
Total equity in earnings of unconsolidated affiliates	$ 172	$ 142	$ 26

	Years Ended December 31,		
	2013	2012	2011
Segment Adjusted EBITDA:			
Intrastate transportation and storage	$ 464	$ 601	$ 667
Interstate transportation and storage	1,269	1,013	373
Midstream	479	467	421
NGL transportation and services	351	209	127
Investment in Sunoco Logistics	871	219	—
Retail marketing	325	109	—
All other	194	126	193
Total Segment Adjusted EBITDA	3,953	2,744	1,781
Depreciation and amortization	(1,032)	(656)	(405)
Interest expense, net of interest capitalized	(849)	(665)	(474)
Gain on deconsolidation of Propane Business	—	1,057	—
Gain on sale of AmeriGas common units	87	—	—
Goodwill impairment	(689)	—	—
Gains (losses) on interest rate derivatives	44	(4)	(77)
Non-cash unit-based compensation expense	(47)	(42)	(38)
Unrealized gains (losses) on commodity risk management activities	51	(9)	(11)
LIFO valuation adjustments	3	(75)	—
Loss on extinguishment of debt	—	(115)	—
Non-operating environmental remediation	(168)	—	—
Adjusted EBITDA related to discontinued operations	(76)	(99)	(23)
Adjusted EBITDA related to unconsolidated affiliates	(629)	(480)	(56)
Equity in earnings of unconsolidated affiliates	172	142	26
Other, net	12	22	(4)
Income from continuing operations before income tax expense	$ 832	$ 1,820	$ 719

	December 31,		
	2013	2012	2011
Total assets:			
Intrastate transportation and storage	$ 4,606	$ 4,691	$ 4,785
Interstate transportation and storage	10,988	11,794	3,661
Midstream	3,133	4,946	2,513
NGL transportation and services	4,326	3,765	2,360
Investment in Sunoco Logistics	11,650	10,291	—
Retail marketing	3,936	3,926	—
All other	5,063	3,817	2,200
Total	$ 43,702	$ 43,230	$ 15,519

	Years Ended December 31,		
	2013	2012	2011
Additions to property, plant and equipment excluding acquisitions, net of contributions in aid of construction costs (accrual basis):			
Intrastate transportation and storage	$ 47	$ 37	$ 53
Interstate transportation and storage	152	133	207
Midstream	565	1,317	837
NGL transportation and services	443	1,302	325
Investment in Sunoco Logistics	1,018	139	—
Retail marketing	176	58	—
All other	54	63	62
Total	$ 2,455	$ 3,049	$ 1,484

	December 31,		
	2013	2012	2011
Advances to and investments in unconsolidated affiliates:			
Intrastate transportation and storage	$ 1	$ 2	$ 1
Interstate transportation and storage	2,040	2,142	173
Midstream	—	1	—
NGL transportation and services	29	29	27
Investment in Sunoco Logistics	125	118	—
Retail marketing	22	21	—
All other	2,219	1,189	—
Total	$ 4,436	$ 3,502	$ 201

15. QUARTERLY FINANCIAL DATA (UNAUDITED):

Summarized unaudited quarterly financial data is presented below. The sum of net income per Limited Partner unit by quarter does not equal the net income per limited partner unit for the year due to the computation of income allocation between the General Partner and Limited Partners and variations in the weighted average units outstanding used in computing such amounts. ETC OLP's business is also seasonal due to the operations of ET Fuel System and the HPL System. We expect margin related to the HPL System operations to be higher during the periods from November through March of each year and lower during the periods from April through October of each year due to the increased demand for natural gas during the cold weather. However, 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.

	Quarter Ended				
	March 31	June 30	September 30	December 31	Total Year
2013:					
Revenues	$ 10,854	$ 11,551	$ 11,902	$ 12,032	$ 46,339
Gross profit	1,260	1,322	1,248	1,305	5,135
Operating income (loss)	534	632	526	(151)	1,541
Net income (loss)	424	413	404	(473)	768
Limited Partners' interest in net income (loss)	194	165	209	(666)	(98)
Basic net income (loss) per limited partner unit	$ 0.63	$ 0.53	$ 0.55	$ (1.90)	$ (0.18)
Diluted net income (loss) per limited partner unit	$ 0.63	$ 0.53	$ 0.55	$ (1.90)	$ (0.18)

The three months ended December 31, 2013 was impacted by ETP's recognition of a goodwill impairment of $689 million. For the three months ended December 31, 2013, distributions paid for the period exceeded net income attributable to partners by $1.12 billion. Accordingly, the distributions paid to the General Partner, including incentive distributions, further exceeded net income, and as a result, a net loss was allocated to the Limited Partners for the period.

	Quarter Ended				
	March 31	June 30	September 30	December 31	Total Year
2012:					
Revenues	$ 1,323	$ 1,596	$ 1,802	$ 10,981	$ 15,702
Gross profit	542	797	776	1,321	3,436
Operating income	209	357	365	463	1,394
Net income	1,088	135	64	361	1,648
Limited Partners' interest in net income (loss)	998	2	(80)	188	1,108
Basic net income (loss) per limited partner unit	$ 4.36	$ 0.00	$ (0.33)	$ 0.62	$ 4.43
Diluted net income (loss) per limited partner unit	$ 4.35	$ 0.00	$ (0.33)	$ 0.62	$ 4.42

For the three months ended September 30, 2012, distributions paid for the period exceeded net income attributable to partners by $356 million. Accordingly, the distributions paid to the General Partner, including incentive distributions, further exceeded net income, and as a result, a net loss was allocated to the Limited Partners for the period. In addition, for the three months ended June 30, 2012 distributions paid for the period exceeded net income attributable to partners by $223 million. The allocation of the distributions in excess of net income is based on the proportionate ownership interests of the Limited Partners and General Partner. Based on this allocation approach, net income per Limited Partner unit (basic and diluted) for the three months ended June 30, 2012 was approximately zero, after taking into account distributions to be paid with respect to incentive distribution rights and employee unit awards.

3. ENERGY TRANSFER PARTNERS GP, L.P. AND SUBSIDIARIES CONSOLIDATED FINANCIAL STATEMENTS

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Partners
Energy Transfer Partners GP, L.P.

We have audited the accompanying consolidated balance sheets of Energy Transfer Partners GP, L.P. (a Delaware limited partnership) and subsidiaries (the "Partnership") as of December 31, 2013 and 2012, 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, 2013. 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. as of December 31, 2012 and for the period from October 5, 2012 to December 31, 2012, 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. We were not engaged to perform an audit of the Partnership's internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Partnership's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, 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 GP, L.P. and subsidiaries as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America.

/s/ GRANT THORNTON LLP

Dallas, Texas
February 27, 2014

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

	December 31, 2013	December 31, 2012
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 549	$ 311
Accounts receivable, net	3,359	2,910
Accounts receivable from related companies	165	94
Inventories	1,765	1,495
Exchanges receivable	56	55
Price risk management assets	35	21
Current assets held for sale	—	184
Other current assets	310	334
Total current assets	6,239	5,404
PROPERTY, PLANT AND EQUIPMENT	28,430	27,412
ACCUMULATED DEPRECIATION	(2,483)	(1,639)
	25,947	25,773
NON-CURRENT ASSETS HELD FOR SALE	—	985
ADVANCES TO AND INVESTMENTS IN UNCONSOLIDATED AFFILIATES	4,436	3,502
NON-CURRENT PRICE RISK MANAGEMENT ASSETS	17	42
GOODWILL	4,758	5,635
INTANGIBLE ASSETS, net	1,568	1,561
OTHER NON-CURRENT ASSETS, net	766	357
Total assets	$ 43,731	$ 43,259

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

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

	December 31, 2013	December 31, 2012
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 3,627	$ 3,002
Accounts payable to related companies	45	24
Exchanges payable	285	156
Price risk management liabilities	45	110
Accrued and other current liabilities	1,428	1,562
Current maturities of long-term debt	637	609
Current liabilities held for sale	—	85
Total current liabilities	6,067	5,548
NON-CURRENT LIABILITIES HELD FOR SALE	—	142
LONG-TERM DEBT, less current maturities	16,451	15,442
LONG-TERM NOTES PAYABLE — RELATED PARTY	—	166
NON-CURRENT PRICE RISK MANAGEMENT LIABILITIES	54	129
DEFERRED INCOME TAXES	3,762	3,476
OTHER NON-CURRENT LIABILITIES	1,080	995
COMMITMENTS AND CONTINGENCIES (Note 10)		
EQUITY:		
General Partner	—	—
Limited Partners:		
Class A Limited Partner interest	71	86
Class B Limited Partner interest	129	131
Total partners' capital	200	217
Noncontrolling interest	16,117	17,144
Total equity	16,317	17,361
Total liabilities and equity	$ 43,731	$ 43,259

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

ENERGY TRANSFER PARTNERS GP, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Dollars in millions)

	Years Ended December 31,		
	2013	2012	2011
REVENUES:			
Natural gas sales	$ 3,165	$ 2,387	$ 2,534
NGL sales	2,817	1,718	1,113
Crude sales	15,477	2,872	—
Gathering, transportation and other fees	2,590	2,007	1,488
Refined product sales	18,479	5,299	—
Other	3,811	1,419	1,664
Total revenues	46,339	15,702	6,799
COSTS AND EXPENSES:			
Cost of products sold	41,204	12,266	4,175
Operating expenses	1,388	951	799
Depreciation and amortization	1,032	656	405
Selling, general and administrative	485	435	173
Goodwill impairment	689	—	—
Total costs and expenses	44,798	14,308	5,552
OPERATING INCOME	1,541	1,394	1,247
OTHER INCOME (EXPENSE):			
Interest expense, net of interest capitalized	(849)	(665)	(474)
Equity in earnings of unconsolidated affiliates	172	142	26
Gain on deconsolidation of Propane Business	—	1,057	—
Gain on sale of AmeriGas common units	87	—	—
Loss on extinguishment of debt	—	(115)	—
Gains (losses) on interest rate derivatives	44	(4)	(77)
Non-operating environmental remediation	(168)	—	—
Other, net	5	11	(3)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE	832	1,820	719
Income tax expense from continuing operations	97	63	19
INCOME FROM CONTINUING OPERATIONS	735	1,757	700
Income (loss) from discontinued operations	33	(109)	(3)
NET INCOME	768	1,648	697
LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTEREST	262	1,187	264
NET INCOME ATTRIBUTABLE TO PARTNERS	506	461	433
GENERAL PARTNER’S INTEREST IN NET INCOME	—	—	—
LIMITED PARTNERS’ INTEREST IN NET INCOME	$ 506	$ 461	$ 433

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

ENERGY TRANSFER PARTNERS GP, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Dollars in millions)

	Years Ended December 31,		
	2013	2012	2011
Net income	$ 768	$ 1,648	$ 697
Other comprehensive income (loss), net of tax:			
Reclassification to earnings of gains and losses on derivative instruments accounted for as cash flow hedges	(4)	(14)	(38)
Change in value of derivative instruments accounted for as cash flow hedges	(1)	8	19
Change in value of available-for-sale securities	2	—	(1)
Actuarial gain (loss) relating to pension and other postretirement benefits	66	(10)	—
Foreign currency translation adjustment	(1)	—	—
Change in other comprehensive income from equity investments	17	(9)	—
	79	(25)	(20)
Comprehensive income	847	1,623	677
Less: Comprehensive income attributable to noncontrolling interest	341	1,162	244
Comprehensive income attributable to partners	$ 506	$ 461	$ 433

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

ENERGY TRANSFER PARTNERS GP, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF EQUITY
(Dollars in millions)

	General Partner	Limited Partners	Noncontrolling Interest		Total
Balance, December 31, 2010	$ —	$ 204	$ 4,568		$ 4,772
Distributions to partners	—	(426)	—		(426)
Distributions to noncontrolling interest	—	—	(777)		(777)
ETP units issued for cash	—	—	1,467		1,467
Capital contributions from noncontrolling interest	—	—	645		645
ETP issuance of units in acquisitions	—	—	3		3
Non-cash compensation expense, net of units tendered by employees for tax withholdings	—	—	30	30	30
Other comprehensive loss, net of tax	—	—	(20)		(20)
Other, net	—	—	(12)		(12)
Net income	—	433	264		697
Balance, December 31, 2011	—	211	6,168		6,379
Distributions to partners	—	(454)	—		(454)
Distributions to noncontrolling interest	—	—	(1,122)		(1,122)
ETP units issued for cash	—	—	791		791
Capital contributions from noncontrolling interest	—	—	343		343
Sunoco Merger (see Note 3)	—	—	5,868		5,868
Holdco Transaction (see Note 3)	—	—	3,913		3,913
Issuance of ETP units in other acquisitions (excluding Sunoco)	—	—	7		7
Non-cash compensation expense, net of units tendered by employees for tax withholdings	—	—	27		27
Other comprehensive loss net of tax	—	—	(25)		(25)
Other, net	—	(1)	(13)		(14)
Net income	—	461	1,187		1,648
Balance, December 31, 2012	—	217	17,144		17,361
Distributions to partners	—	(523)	—		(523)
Distributions to noncontrolling interest	—	—	(1,661)		(1,661)
ETP units issued for cash	—	—	1,611		1,611
Capital contributions from noncontrolling interest	—	—	137		137
Holdco Acquisition and SUGS Contribution (see Note 3)	—	—	(1,440)		(1,440)
Other comprehensive income, net of tax	—	—	79		79
Other, net	—	—	(15)		(15)
Net income	—	506	262		768
Balance, December 31, 2013	$ —	$ 200	$ 16,117		$ 16,317

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

ENERGY TRANSFER PARTNERS GP, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Dollars in millions)

	Years Ended December 31,		
	2013	2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 768	$ 1,648	$ 697
Reconciliation of net income to net cash provided by operating activities:			
Depreciation and amortization	1,032	656	405
Deferred income taxes	48	62	4
Gain on curtailment of other postretirement benefits	—	(15)	—
Amortization included in interest expense	(80)	(35)	10
Loss on extinguishment of debt	—	115	—
LIFO valuation adjustments	(3)	75	—
Non-cash compensation expense	47	42	38
Gain on deconsolidation of Propane Business	—	(1,057)	—
Gain on sale of AmeriGas common units	(87)	—	—
Goodwill impairment	689	—	—
Write-down of assets included in loss from discontinued operations	—	132	—
Equity in earnings of unconsolidated affiliates	(172)	(142)	(26)
Distributions from unconsolidated affiliates	247	132	29
Other non-cash	42	68	29
Net change in operating assets and liabilities, net of effects of acquisitions and deconsolidations (see Note 2)	(146)	(475)	166
Net cash provided by operating activities	2,385	1,206	1,352
CASH FLOWS FROM INVESTING ACTIVITIES:			
Cash paid for Citrus Merger	—	(1,895)	—
Cash proceeds from contribution and sale of propane operations	—	1,443	—
Cash proceeds from SUGS Contribution (See Note 3)	504	—	—
Cash paid for Holdco Acquisition (See Note 3)	(1,332)	—	—
Cash proceeds from the sale of the MGE and NEG assets (See Note 3)	1,008	—	—
Cash proceeds from the sale of AmeriGas common units	346	—	—
Cash (paid) received from all other acquisitions	(405)	531	(1,972)
Capital expenditures (excluding allowance for equity funds used during construction)	(2,575)	(2,840)	(1,416)
Contributions in aid of construction costs	52	35	25
Contributions to unconsolidated affiliates	(1)	(30)	(222)
Distributions from unconsolidated affiliates in excess of cumulative earnings	217	130	22
Proceeds from sale of disposal group	—	207	—
Proceeds from the sale of assets	53	18	9
Restricted cash	(348)	5	—
Other	21	111	1
Net cash used in investing activities	(2,460)	(2,285)	(3,553)

CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from borrowings	8,001	8,208	6,594
Repayments of long-term debt	(7,016)	(6,598)	(5,217)
Proceeds from borrowings from affiliates	—	221	—
Repayments of borrowings from affiliates	(166)	(55)	—
Net proceeds from issuance of ETP Limited Partner units	1,611	791	1,467
Capital contributions received from noncontrolling interest	147	320	645
Distributions to partners	(523)	(454)	(426)
Distributions to noncontrolling interest	(1,673)	(1,130)	(785)
Debt issuance costs	(32)	(20)	(20)
Other	(36)	—	—
Net cash provided by financing activities	313	1,283	2,258
INCREASE IN CASH AND CASH EQUIVALENTS	238	204	57
CASH AND CASH EQUIVALENTS, beginning of period	311	107	50
CASH AND CASH EQUIVALENTS, end of period	$ 549	$ 311	$ 107

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

ENERGY TRANSFER PARTNERS GP, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Tabular dollar and unit amounts are in millions)

1. OPERATIONS AND ORGANIZATION:

Energy Transfer Partners GP, L.P. ("ETP GP" or "the Partnership") was formed in August 2000 as a Delaware limited partnership. ETP GP is the General Partner and the owner of the general partner interest of Energy Transfer Partners, L.P., a publicly traded master limited partnership ("ETP"). ETP GP is owned 99.99% by its limited partners, and 0.01% by its general partner, Energy Transfer Partners, L.L.C. ("ETP LLC").

Energy Transfer Equity, L.P. ("ETE") is the 100% owner of ETP LLC and also owns 100% of our Class A and Class B Limited Partner interests. For more information on our Class A and Class B Limited Partner interests, see Note 6.

Financial Statement Presentation

The consolidated financial statements and notes thereto of ETP GP and its subsidiaries presented herein for the years ended December 31, 2013, 2012 and 2011, have been prepared in accordance with GAAP. We consolidate all majority-owned subsidiaries and subsidiaries we control, even if we do not have a majority ownership. All significant intercompany transactions and accounts are eliminated in consolidation. Management has evaluated subsequent events through February 27, 2014, the date the financial statements were issued.

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

In October 2012, we sold Canyon and the results of continuing operations of Canyon have been reclassified to income (loss) from discontinued operations. In 2013, Southern Union sold its distribution operations. The results of operations of the distribution operations have been reported as income (loss) from discontinued operations. The assets and liabilities of the disposal group have been reported as assets and liabilities held for sale as of December 31, 2012.

In accordance with GAAP, we have accounted for the Holdco Transaction (described in Note 3), whereby ETP obtained control of Southern Union, as a reorganization of entities under common control. Accordingly, our 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).

Business Operations

Our activities are primarily conducted through our operating subsidiaries (collectively, the "Operating Companies") as follows:

- ETC OLP, a Texas limited partnership primarily engaged in midstream and intrastate transportation and storage natural gas operations. ETC OLP owns and operates, through its wholly and majority-owned subsidiaries, natural gas gathering systems, intrastate natural gas pipeline systems and gas processing plants and is engaged in the business of purchasing, gathering, transporting, processing, and marketing natural gas and NGLs in the states of Texas, Louisiana, New Mexico and West Virginia. ETC OLP's intrastate transportation and storage operations primarily focus on transporting natural gas in Texas through our Oasis pipeline, ET Fuel System, East Texas pipeline and HPL System. ETC OLP's midstream operations focus on the gathering, compression, treating, conditioning and processing of natural gas, primarily on or through our Southeast Texas System, Eagle Ford System, North Texas System and Northern Louisiana assets. ETC OLP also owns a 70% interest in Lone Star and also owns a convenience store operator with approximately 300 company-owned and dealer locations.
- ET Interstate, a Delaware limited liability company with revenues consisting primarily of fees earned from natural gas transportation services and operational gas sales. ET Interstate is the parent company of:
  - Transwestern, a Delaware limited liability company engaged in interstate transportation of natural gas. Transwestern's revenues consist primarily of fees earned from natural gas transportation services and operational gas sales.
  - ETC FEP, a Delaware limited liability company that directly owns a 50% interest in FEP, which owns 100% of the Fayetteville Express interstate natural gas pipeline.
  - ETC Tiger, a Delaware limited liability company engaged in interstate transportation of natural gas.

    - CrossCountry, a Delaware limited liability company that indirectly owns a 50% interest in Citrus Corp., which owns 100% of the FGT interstate natural gas pipeline.

- ETC Compression, a Delaware limited liability company engaged in natural gas compression services and related equipment sales.

- Sunoco Logistics, a publicly traded Delaware limited partnership that owns and operates a logistics business, consisting of refined products and crude oil pipelines, terminalling and storage assets, and refined products and crude oil acquisition and marketing assets.

- Holdco, a Delaware limited liability company that indirectly owns Panhandle and Sunoco. As discussed in Note 3, ETP acquired ETE's 60% interest in Holdco on April 30, 2013. Panhandle and Sunoco operations are described as follows:

    - Panhandle owns and operates assets in the regulated and unregulated natural gas industry and is primarily engaged in the transportation, storage and distribution of natural gas in the United States. As discussed in Note 3, on April 30, 2013, Southern Union completed its contribution to Regency of all of the issued and outstanding membership interests in Southern Union Gathering Company, LLC, and its subsidiaries, including SUGS. Also, as discussed in Note 3, Southern Union completed its sale of the assets of MGE and NEG in 2013. Additionally, as discussed in Note 3, in January 2014, Panhandle consummated a merger with Southern Union, the indirect parent of Panhandle, and PEPL Holdings, the sole limited partner of Panhandle, pursuant to which each of Southern Union and PEPL Holdings were merged with and into Panhandle, with Panhandle surviving the merger.

    - Sunoco owns and operates retail marketing assets, that sell gasoline and middle distillates and operate convenience stores primarily on the east coast and in the midwest region of the United States.

The Partnership, ETP, the Operating Companies and their subsidiaries are collectively described in this report as "we," "us," "our," "ETP," "Energy Transfer" or the "Partnership."

2. ESTIMATES, SIGNIFICANT ACCOUNTING POLICIES AND BALANCE SHEET DETAIL:

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 operations 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 estimated operating results 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 or installation. 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 operations' 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. Fuel retained for a fee is typically valued at market prices.

Our intrastate transportation and storage operations 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 our marketing operations, and from producers at the wellhead.

In addition, our intrastate transportation and storage operations 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 operations 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 operations, 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, (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, (iv) purchasing all or a specified percentage of natural gas and/or NGL delivered from producers and treating or processing our plant facilities, and (v) making other direct purchases of natural gas and/or NGL at specified delivery points to meet operational or marketing obligations. 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.

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.

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.

Terminalling and storage revenues are recognized at the time the services are provided. Pipeline revenues are recognized upon delivery of the barrels to the location designated by the shipper. Crude oil acquisition and marketing revenues, as well as refined product marketing revenues, are recognized when title to the product is transferred to the customer. Revenues are not recognized for crude oil exchange transactions, which are entered into primarily to acquire crude oil of a desired quality or to reduce transportation costs by taking delivery closer to end markets. Any net differential for exchange transactions is recorded as an adjustment of inventory costs in the purchases component of cost of products sold and operating expenses in the statements of operations.

Our retail marketing operations sells gasoline and diesel in addition to a broad mix of merchandise such as groceries, fast foods and beverages at its convenience stores. In addition, some of Sunoco's retail outlets provide a variety of car care services. Revenues related to the sale of products are recognized when title passes, while service revenues are recognized when services are provided. Title passage generally occurs when products are shipped or delivered in accordance with the terms of the respective sales agreements. In addition, revenues are not recognized until sales prices are fixed or determinable and collectability is reasonably assured.

Regulatory Accounting – Regulatory Assets and Liabilities

Our interstate transportation and storage operations are subject to regulation by certain state and federal authorities, and certain subsidiaries in those operations have accounting policies that conform to the accounting requirements and ratemaking practices of the regulatory authorities. The application of these accounting policies allows certain of our regulated entities 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 these entities, 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.

Southern Union recorded regulatory assets with respect to its distribution operations. At December 31, 2012, we had $123 million of regulatory assets included in the consolidated balance sheet as non-current assets held for sale. Southern Union's distribution operations were sold in 2013.

Although Panhandle's natural gas transmission systems and storage operations are subject to the jurisdiction of FERC in accordance with the Natural Gas Act of 1938 and Natural Gas Policy Act of 1978, it does not currently apply regulatory accounting policies in accounting for its operations. In 1999, prior to its acquisition by Southern Union, Panhandle discontinued the application of regulatory accounting policies primarily due to the level of discounting from tariff rates and its inability to recover specific costs.

Cash, Cash Equivalents and Supplemental Cash Flow Information

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

We place our cash deposits and temporary cash investments with high credit quality financial institutions. At times, our cash and cash equivalents may be uninsured or in deposit accounts that exceed the Federal Deposit Insurance Corporation insurance limit.

The net change in operating assets and liabilities (net of acquisitions) included in cash flows from operating activities is comprised as follows:

	Years Ended December 31,		
	2013	2012	2011
Accounts receivable	$ (458)	$ 300	$ 3
Accounts receivable from related companies	(17)	(50)	(28)
Inventories	(256)	(253)	68
Exchanges receivable	(24)	11	3
Other current assets	(56)	571	(62)
Other non-current assets, net	(22)	(53)	7
Accounts payable	525	(979)	31
Accounts payable to related companies	(122)	100	6
Exchanges payable	131	—	3
Accrued and other current liabilities	152	(151)	60
Other non-current liabilities	151	25	—
Price risk management assets and liabilities, net	(150)	4	75
Net change in operating assets and liabilities, net of effects of acquisitions and deconsolidations	$ (146)	$ (475)	$ 166

Non-cash investing and financing activities and supplemental cash flow information are as follows:

	Years Ended December 31,		
	2013	2012	2011
NON-CASH INVESTING ACTIVITIES:			
Accrued capital expenditures	$ 167	$ 359	$ 202
AmeriGas limited partner interest received in exchange for contribution of Propane Business	$ —	$ 1,123	$ —
Regency common and Class F units received in exchange for contribution of SUGS	$ 961	$ —	$ —
NON-CASH FINANCING ACTIVITIES:			
Long-term debt assumed and non-compete agreement notes payable issued in acquisitions	$ —	$ 6,658	$ 4
Issuance of ETP common units in connection with certain acquisitions	$ —	$ 2,295	$ 3
Issuance of ETP Common Units in connection with the Holdco Acquisition	$ 2,464	$ —	$ —
Contributions receivable related to noncontrolling interest	$ 13	$ 23	$ —
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid for interest, net of interest capitalized	$ 903	$ 678	$ 476
Cash paid for income taxes	$ 57	$ 22	$ 24

Accounts Receivable

Our midstream, NGL and intrastate transportation and storage operations deal with counterparties that are typically either investment grade or are otherwise secured with a letter of credit or other form of security (corporate guaranty prepayment or master setoff agreement). Management reviews midstream and intrastate transportation and storage accounts receivable balances bi-weekly. Credit limits are assigned and monitored for all counterparties of the midstream and intrastate transportation and storage operations. Bad debt expense related to these receivables is recognized at the time an account is deemed uncollectible.

Sunoco Logistics extends credit terms to certain customers after review of various credit indicators, including the customer's credit rating. Outstanding customer receivable balances are regularly reviewed for possible non-payment indicators and reserves are recorded for doubtful accounts based upon management's estimate of collectability at the time of review. Actual balances are charged against the reserve when all collection efforts have been exhausted.

Our interstate transportation and storage operations have a concentration of customers in the electric and gas utility industries as well as natural gas producers. This concentration of customers may impact our overall exposure to credit risk, either positively or negatively, in that the customers may be similarly affected by changes in economic or other conditions. From time to time, specifically identified customers having perceived credit risk are required to provide prepayments or other forms of collateral. Management believes that the portfolio of receivables, which includes regulated electric utilities, regulated local distribution companies and municipalities, is subject to minimal credit risk. Our interstate transportation and storage operations establish an allowance for doubtful accounts on trade receivables based on the expected ultimate recovery of these receivables and consider many factors including historical customer collection experience, general and specific economic trends and known specific issues related to individual customers, sectors and transactions that might impact collectability.

Our retail marketing operations extends credit to customers after a review of credit rating and other credit indicators. Management records reserves for bad debt by computing a proportion of average write-off activity over the past five years in comparison to the outstanding balance in accounts receivable. This proportion is then applied to the accounts receivable balance at the end of the reporting period to calculate a current estimate of what is uncollectible. The credit department and business line managers make the decision to write off an account, based on understanding of the potential collectability.

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

Inventories

Inventories consist principally of natural gas held in storage, crude oil, petroleum and chemical products. Natural gas held in storage is valued at the lower of cost or market utilizing the weighted-average cost method. The cost of crude oil and petroleum and chemical products is determined using the last-in, first out method. The cost of appliances, parts and fittings is determined by the first-in, first-out method.

Inventories consisted of the following:

	December 31,	
	2013	2012
Natural gas and NGLs	$ 519	$ 334
Crude oil	488	418
Refined products	597	572
Appliances, parts and fittings, and other	161	171
Total inventories	$ 1,765	$ 1,495

We utilize commodity derivatives to manage price volatility associated with our natural gas inventory. Changes in fair value of designated hedged inventory are recorded in inventory on our consolidated balance sheets and cost of products sold in our consolidated statements of operations.

Exchanges

Exchanges consist of natural gas and NGL delivery imbalances (over and under deliveries) with others. These amounts, which are valued at market prices or weighted average market prices pursuant to contractual imbalance agreements, turn over monthly and are recorded as exchanges receivable or exchanges payable on our consolidated balance sheets. These imbalances are generally settled by deliveries of natural gas or NGLs, but may be settled in cash, depending on contractual terms.

Other Current Assets

Other current assets consisted of the following:

	December 31,	
	2013	2012
Deposits paid to vendors	$ 49	$ 41
Prepaid and other	261	293
Total other current assets	$ 310	$ 334

Property, Plant and Equipment

Property, plant and equipment are stated at cost less accumulated depreciation. Depreciation is computed using the straight-line method over the estimated useful or FERC mandated lives of the assets, if applicable. 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 our consolidated statements of operations.

We review property, plant and equipment for impairment whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. If such a review should indicate that the carrying amount of long-lived assets is not recoverable, we reduce the carrying amount of such assets to fair value. A write down of the carrying amounts of the Canyon assets to their fair values was recorded for approximately $128 million during the year ended December 31, 2012.

Capitalized interest is included for pipeline construction projects, except for certain interstate projects for which an allowance for funds used during construction (“AFUDC”) is accrued. Interest is capitalized based on the current borrowing rate of our revolving credit facility when the related costs are incurred. AFUDC is calculated under guidelines prescribed by the FERC and capitalized as part of the cost of utility plant for interstate projects. It represents the cost of servicing the capital invested in construction work-in-process. AFUDC is segregated into two component parts – borrowed funds and equity funds.

Components and useful lives of property, plant and equipment were as follows:

	December 31, 2013	December 31, 2012
Land and improvements	$ 878	$ 551
Buildings and improvements (5 to 45 years)	900	568
Pipelines and equipment (5 to 83 years)	16,966	17,031
Natural gas and NGL storage facilities (5 to 46 years)	1,083	1,057
Bulk storage, equipment and facilities (2 to 83 years)	1,933	1,745
Tanks and other equipment (5 to 40 years)	1,685	1,187
Retail equipment (3 to 99 years)	450	258
Vehicles (1 to 25 years)	124	77
Right of way (20 to 83 years)	1,901	2,042
Furniture and fixtures (2 to 25 years)	48	48
Linepack	116	116
Pad gas	52	58
Other (1 to 48 years)	626	986
Construction work-in-process	1,668	1,688
	28,430	27,412
Less – Accumulated depreciation	(2,483)	(1,639)
Property, plant and equipment, net	$ 25,947	$ 25,773

We recognized the following amounts of depreciation expense for the periods presented:

	Years Ended December 31, 2013	2012	2011
Depreciation expense[(1)]	$ 944	$ 615	$ 380
Capitalized interest, excluding AFUDC	$ 43	$ 99	$ 11

(1) Depreciation expense amounts have been adjusted by $26 million for the year ended December 31, 2011 to present Canyon's operations as discontinued operations.

Advances to and Investments in Unconsolidated Affiliates

We own interests in a number of related businesses that are accounted for by the equity method. In general, we use the equity method of accounting for an investment for which we exercise significant influence over, but do not control, the investee's operating and financial policies.

Goodwill

Goodwill is tested for impairment annually or more frequently if circumstances indicate that goodwill might be impaired. Our annual impairment test is performed as of August 31 for subsidiaries in our intrastate transportation and storage and midstream operations and during the fourth quarter for subsidiaries in our interstate transportation and storage, NGL transportation and services, and retail marketing operations and all others. We recorded goodwill impairments for the periods presented in these consolidated financial statements.

Changes in the carrying amount of goodwill were as follows:

	Intrastate Transportation and Storage	Interstate Transportation and Storage	Midstream	NGL Transportation and Services	Investment in Sunoco Logistics	Retail Marketing	All Other	ETP GP	Total
Balance, December 31, 2011	$ 10	$ 99	$ 37	$ 432	$ —	$ —	$ 642	$ 29	$ 1,249
Goodwill acquired	—	1,785	338	—	1,368	1,272	375	—	5,138
Goodwill sold in deconsolidation of Propane Business	—	—	—	—	—	—	(619)	—	(619)
Goodwill allocated to the disposal group	—	—	—	—	—	—	(133)	—	(133)
Balance, December 31, 2012	10	1,884	375	432	1,368	1,272	265	29	5,635
Goodwill acquired	—	—	—	—	—	156	—	—	156
Goodwill disposed	—	—	(337)	—	—	— —	—	—	(337)
Goodwill impairment	—	(689)	—	—	—	—	—	—	(689)
Other	—	—	(2)	—	(22)	17	—	—	(7)
Balance, December 31, 2013	$ 10	$ 1,195	$ 36	$ 432	$ 1,346	$ 1,445	$ 265	29	$ 4,758

Goodwill is recorded at the acquisition date based on a preliminary purchase price allocation and generally may be adjusted when the purchase price allocation is finalized. We recorded a net decrease in goodwill of $877 million during the year ended December 31, 2013 primarily due to Trunkline LNG's goodwill impairment of $689 million (see below) and a decrease of $337 million as a result of the SUGS Contribution (see Note 3). These decreases were offset by additional goodwill of $156 million from acquisitions in 2013. This additional goodwill is not expected to be deductible for tax purposes.

During the fourth quarter of 2013, we performed a goodwill impairment test on our Trunkline LNG reporting unit. In accordance with GAAP, we performed step one of the goodwill impairment test and determined that the estimated fair value of the Trunkline LNG reporting unit was less than its carrying amount primarily due to changes related to (i) the structure and capitalization of the planned LNG export project at Trunkline LNG's Lake Charles facility, (ii) an analysis of current macroeconomic factors, including global natural gas prices and relative spreads, as of the date of our assessment, (iii) judgments regarding the prospect of obtaining regulatory approval for a proposed LNG export project and the uncertainty associated with the timing of such approvals, and (iv) changes in assumptions related to potential future revenues from the import facility and the proposed export facility. An assessment of these factors in the fourth quarter of 2013 led to a conclusion that the estimated fair value of the Trunkline LNG reporting unit was less than its carrying amount. We then applied the second step in the goodwill impairment test, allocating the estimated fair value of the reporting unit among all of the assets and liabilities of the reporting unit in a hypothetical purchase price allocation. The assets and liabilities of the reporting unit had recently been measured at fair value in 2012 as a result of the acquisition of Southern Union, and those estimated fair values had been recorded at the reporting unit through the application of "push-down" accounting. For purposes of the hypothetical purchase price allocation used in the goodwill impairment test, we estimated the fair value of the assets and liabilities of the reporting unit in a manner similar to the original purchase price allocation. In allocating value to the property, plant and equipment, we used current replacement costs adjusted for assumed depreciation. We also included the estimated fair value of working capital and identifiable intangible assets in the reporting unit. We adjusted deferred income taxes based on these estimated fair values. Based on this hypothetical purchase price allocation, estimated goodwill was $184 million, which was less than the balance of $873 million that had originally been recorded by the reporting unit through "push-down" accounting in 2012. As a result, we recorded a goodwill impairment of $689 million during the fourth quarter of 2013.

No other goodwill impairments were identified or recorded for our reporting units.

Intangible Assets

Intangible assets are stated at cost, net of amortization computed on the straight-line method. We eliminate from our balance sheet the gross carrying amount and the related accumulated amortization for any fully amortized intangibles in the year they are fully amortized.

Components and useful lives of intangible assets were as follows:

	December 31, 2013		December 31, 2012	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Amortizable intangible assets:				
Customer relationships, contracts and agreements (3 to 46 years)	$ 1,393	$ (164)	$ 1,290	$ (80)
Patents (9 years)	48	(6)	48	(1)
Other (10 to 15 years)	4	(1)	4	(1)
Total amortizable intangible assets	$ 1,445	$ (171)	$ 1,342	$ (82)
Non-amortizable intangible assets:				
Trademarks	294	—	301	—
Total intangible assets	$ 1,739	$ (171)	$ 1,643	$ (82)

Aggregate amortization expense of intangible assets was as follows:

	Years Ended December 31,		
	2013	2012	2011
Reported in depreciation and amortization	$ 88	$ 36	$ 24

Estimated aggregate amortization expense for the next five years is as follows:

Years Ending December 31:	
2014	$ 93
2015	93
2016	93
2017	93
2018	92

We review amortizable intangible assets for impairment whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. If such a review should indicate that the carrying amount of amortizable intangible assets is not recoverable, we reduce the carrying amount of such assets to fair value. We review non-amortizable intangible assets for impairment annually, or more frequently if circumstances dictate.

Other Non-Current Assets, net

Other non-current assets, net are stated at cost less accumulated amortization. Other non-current assets, net consisted of the following:

	December 31,	
	2013	2012
Unamortized financing costs (3 to 30 years)	$ 70	$ 54
Regulatory assets	86	87
Deferred charges	144	140
Restricted funds	378	—
Other	88	76
Total other non-current assets, net	$ 766	$ 357

Restricted funds primarily consisted of restricted cash held in our wholly-owned captive insurance companies.

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 estimate 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, 2013 and 2012 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.

Below is a schedule of AROs by entity recorded as other non-current liabilities in the consolidated balance sheet:

	December 31,	
	2013	2012
Southern Union	$ 55	$ 46
Sunoco	84	53
Sunoco Logistics	41	41
	$ 180	$ 140

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, 2013, there were no legally restricted funds for the purpose of settling AROs.

Accrued and Other Current Liabilities

Accrued and other current liabilities consisted of the following:

	December 31,	
	2013	2012
Interest payable	$ 294	$ 256
Customer advances and deposits	126	44
Accrued capital expenditures	166	356
Accrued wages and benefits	155	236
Taxes payable other than income taxes	214	203
Income taxes payable	3	40
Deferred income taxes	119	130
Other	351	297
Total accrued and other current liabilities	$ 1,428	$ 1,562

Deposits or advances are received from our customers as prepayments for natural gas deliveries in the following month. Prepayments and security deposits may also be required when customers exceed their credit limits or do not qualify for open credit.

Environmental Remediation

We accrue environmental remediation costs for work at identified sites where an assessment has indicated that cleanup costs are probable and reasonably estimable. Such accruals are undiscounted and are based on currently available information, estimated timing of remedial actions and related inflation assumptions, existing technology and presently enacted laws and regulations. If a range of probable environmental cleanup costs exists for an identified site, the minimum of the range is accrued unless some other point in the range is more likely in which case the most likely amount in the range is accrued.

Fair Value of Financial Instruments

The carrying amounts of cash and cash equivalents, accounts receivable and accounts payable approximate their fair value. Price risk management assets and liabilities are recorded at fair value.

Based on the estimated borrowing rates currently available to us and our subsidiaries for loans with similar terms and average maturities, the aggregate fair value and carrying amount of our debt obligations as of December 31, 2013 was $17.69 billion and $17.09 billion, respectively. As of December 31, 2012, the aggregate fair value and carrying amount of our debt obligations was $17.84 billion and $16.22 billion, respectively. The fair value of our consolidated debt obligations is a Level 2 valuation based on the observable inputs used for similar liabilities.

We have 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 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. During the period ended December 31, 2013, no transfers were made between any levels within the fair value hierarchy.

The following tables summarize the fair value of our financial assets and liabilities measured and recorded at fair value on a recurring basis as of December 31, 2013 and 2012 based on inputs used to derive their fair values:

		Fair Value Measurements at December 31, 2013	
	Fair Value Total	Level 1	Level 2
Assets:			
Interest rate derivatives	$ 47	$ —	$ 47
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	5	5	—
Swing Swaps IFERC	8	1	7
Fixed Swaps/Futures	201	201	—
Power:			
Forwards	3	—	3
Natural Gas Liquids – Forwards/Swaps	5	5	—
Refined Products – Futures	5	5	—
Total commodity derivatives	227	217	10
Total assets	$ 274	$ 217	$ 57
Liabilities:			
Interest rate derivatives	$ (95)	$ —	$ (95)
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	(4)	(4)	—
Swing Swaps IFERC	(6)	—	(6)
Fixed Swaps/Futures	(201)	(201)	—
Forward Physical Swaps	(1)	—	(1)
Power:			
Forwards	(1)	—	(1)
Natural Gas Liquids – Forwards/Swaps	(5)	(5)	—
Refined Products – Futures	(5)	(5)	—
Total commodity derivatives	(223)	(215)	(8)
Total liabilities	$ (318)	$ (215)	$ (103)

	Fair Value Total	Fair Value Measurements at December 31, 2012	
		Level 1	Level 2
Assets:			
Interest rate derivatives	$ 55	$ —	$ 55
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	11	11	—
Swing Swaps IFERC	3	—	3
Fixed Swaps/Futures	96	94	2
Options – Puts	1	—	1
Options – Calls	3	—	3
Forward Physical Swaps	1	—	1
Power:			
Forwards	27	—	27
Futures	1	1	—
Options – Calls	2	—	2
Natural Gas Liquids – Swaps	1	1	—
Refined Products – Futures	5	1	4
Total commodity derivatives	151	108	43
Total assets	$ 206	$ 108	$ 98
Liabilities:			
Interest rate derivatives	$ (223)	$ —	$ (223)
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	(18)	(18)	—
Swing Swaps IFERC	(2)	—	(2)
Fixed Swaps/Futures	(103)	(94)	(9)
Options – Puts	(1)	—	(1)
Options – Calls	(3)	—	(3)
Power:			
Forwards	(27)	—	(27)
Futures	(2)	(2)	—
Natural Gas Liquids – Swaps	(3)	(3)	—
Refined Products – Futures	(8)	(1)	(7)
Total commodity derivatives	(167)	(118)	(49)
Total liabilities	$ (390)	$ (118)	$ (272)

At December 31, 2013, the fair value of the Trunkline LNG reporting unit was classified as Level 3 of the fair value hierarchy due to the significance of unobservable inputs developed using company-specific information. We used the income approach to measure the fair value of the Trunkline LNG reporting unit. Under the income approach, we calculated the fair value based on the present value of the estimated future cash flows. The discount rate used, which was an unobservable input, was based on the weighted-average cost of capital adjusted for the relevant risk associated with business-specific characteristics and the uncertainty related to the business's ability to execute on the projected cash flows.

Contributions in Aid of Construction Costs

On certain of our capital projects, third parties are obligated to reimburse us for all or a portion of project expenditures. The majority of such arrangements are associated with pipeline construction and production well tie-ins. Contributions in aid of construction costs (“CIAC”) are netted against our project costs as they are received, and any CIAC which exceeds our total project costs, is recognized as other income in the period in which it is realized.

Shipping and Handling Costs

Shipping and handling costs related to fuel sold are included in cost of products sold. Shipping and handling costs related to fuel consumed for compression and treating are included in operating expenses and are as follows:

	Years Ended December 31,		
	2013	2012	2011
Shipping and handling costs – recorded in operating expenses	$ 28	$ 25	$ 40

Costs and Expenses

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

We record the collection of taxes to be remitted to government authorities on a net basis except for our retail marketing operation in which consumer excise taxes on sales of refined products and merchandise are included in both revenues and costs and expenses in the consolidated statements of operations, with no effect on net income (loss). Excise taxes collected by ETP’s retail marketing operations were $2.22 billion and $573 million for the years ended December 31, 2013 and 2012, respectively.

Income Taxes

ETP GP is not taxable for federal and most state income tax purposes. As a result, our earnings or losses, to the extent not included in a taxable subsidiary, for federal and most state purposes are included in the tax returns of the individual partners. Net earnings for financial statement purposes may differ significantly from taxable income reportable to Unitholders as a result of differences between the tax basis and financial basis of assets and liabilities, differences between the tax accounting and financial accounting treatment of certain items, and due to allocation requirements related to taxable income under the Partnership Agreement.

As a limited partnership, ETP is subject to a statutory requirement that its “qualifying income” (as defined by the Internal Revenue Code, related Treasury Regulations, and IRS pronouncements) exceed 90% of its total gross income, determined on a calendar year basis. If ETP’s qualifying income does not meet this statutory requirement, ETP would be taxed as a corporation for federal and state income tax purposes. For the years ended December 31, 2013, 2012 and 2011, ETP’s qualifying income met the statutory requirement.

The Partnership conducts certain activities through corporate subsidiaries which are subject to federal, state and local income taxes. Holdco, which owns Sunoco and Southern Union, is a corporate subsidiary. The Partnership and its corporate subsidiaries account for income taxes under the asset and liability method.

Under this method, deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using enacted tax rates in effect for the year in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rate is recognized in earnings in the period that includes the enactment date. Valuation allowances are established when necessary to reduce deferred tax assets to the amounts more likely than not to be realized.

The determination of the provision for income taxes requires significant judgment, use of estimates, and the interpretation and application of complex tax laws. Significant judgment is required in assessing the timing and amounts of deductible and taxable items and the probability of sustaining uncertain tax positions. The benefits of uncertain tax positions are recorded in our financial statements only after determining a more-likely-than-not probability that the uncertain tax positions will withstand challenge, if any, from taxing authorities. When facts and circumstances change, we reassess these probabilities and record any changes through the provision for income taxes.

Accounting for Derivative Instruments and Hedging Activities

For qualifying hedges, we formally document, designate and assess the effectiveness of transactions that receive hedge accounting treatment and the gains and losses offset related results on the hedged item in the statement of operations. 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.

At inception of a hedge, we formally document the relationship between the hedging instrument and the hedged item, the risk management objectives, and the methods used for assessing and testing effectiveness and how any ineffectiveness will be measured and recorded. We also assess, both at the inception of the hedge and on a quarterly basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows. If we determine that a derivative is no longer highly effective as a hedge, we discontinue hedge accounting prospectively by including changes in the fair value of the derivative in net income for the period.

If we designate a commodity 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 statements 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 statements of operations.

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

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.

We manage a portion of our interest rate exposures by utilizing interest rate swaps and similar instruments. Certain of our interest rate derivatives are accounted for as either cash flow hedges or fair value hedges. For interest rate derivatives accounted for as either cash flow or fair value hedges, we report realized gains and losses and ineffectiveness portions of those hedges in interest expense. For interest rate derivatives not designated as hedges for accounting purposes, we report realized and unrealized gains and losses on those derivatives in “Gains (losses) on interest rate derivatives” in the consolidated statements of operations.

Pensions and Other Postretirement Benefit Plans

Employers are required to recognize in their balance sheets the overfunded or underfunded status of defined benefit pension and other postretirement plans, measured as the difference between the fair value of the plan assets and the benefit obligation (the projected benefit obligation for pension plans and the accumulated postretirement benefit obligation for other postretirement plans). Each overfunded plan is recognized as an asset and each underfunded plan is recognized as a liability. Employers must recognize the change in the funded status of the plan in the year in which the change occurs through AOCI in equity or are reflected as a regulatory asset or regulatory liability for regulated subsidiaries.

Allocation of Income

For purposes of maintaining partner capital accounts, the Partnership Agreement specifies that items of income and loss shall generally be allocated among the partners in accordance with their percentage interests. The capital account provisions of our Partnership Agreement incorporate principles established for U.S. Federal income tax purposes and are not comparable to the partners’ capital balances reflected under GAAP in our consolidated financial statements. Our net income for partners’ capital and statement of operations presentation purposes is allocated to the General Partner and Limited Partners in accordance with their respective partnership percentages, after giving effect to priority income allocations for incentive distributions, if any, to our General Partner, the holder of the IDRs pursuant to our Partnership Agreement, which are declared and paid following the close of each quarter. Earnings in excess of distributions are allocated to the General Partner and Limited Partners based on their respective ownership interests.

3. ACQUISITIONS, DIVESTITURES AND RELATED TRANSACTIONS:

2014 Transactions

Panhandle Merger

On January 10, 2014, Panhandle consummated a merger with Southern Union, the indirect parent of Panhandle, and PEPL Holdings, the sole limited partner of Panhandle, pursuant to which each of Southern Union and PEPL Holdings were merged with and into Panhandle (the “Panhandle Merger”), with Panhandle surviving the Panhandle Merger. In connection with the Panhandle Merger, Panhandle assumed Southern Union’s obligations under its 7.6% Senior Notes due 2024, 8.25% Senior Notes due 2029 and the Junior Subordinated Notes due 2066. At the time of the Panhandle Merger, Southern Union did not have operations of its own, other than its ownership of Panhandle and noncontrolling interest in PEI Power II, LLC, Regency (31.4 million common units and 6.3 million Class F Units), and ETP (2.2 million Common Units). In connection with the Panhandle Merger, Panhandle also assumed PEPL Holdings’ guarantee of $600 million of Regency senior notes.

Trunkline LNG Transaction

On February 19, 2014, ETE and ETP completed the transfer to ETE of Trunkline LNG, the entity that owns a LNG regasification facility in Lake Charles, Louisiana, from ETP in exchange for the redemption by ETP of 18.7 million ETP Common Units held by ETE. This transaction was effective as of January 1, 2014. The results of Trunkline LNG’s operations have not been presented as discontinued operations and Trunkline LNG’s assets and liabilities have not been presented as held for sale in the Partnership’s consolidated financial statements due to the expected continuing involvement among the entities.

In connection with ETE’s acquisition of Trunkline LNG, ETP agreed to continue to provide management services for ETE through 2015 in relation to both Trunkline LNG’s regasification facility and the development of a liquefaction project at Trunkline LNG’s facility, for which ETE has agreed to pay incremental management fees to ETP of $75 million per year for the years ending December 31, 2014 and 2015. ETE also agreed to provide additional subsidies to ETP through the relinquishment of future incentive distributions, as discussed further in Note 7.

2013 Transactions

Sale of Southern Union’s Distribution Operations

In December 2012, Southern Union entered into a purchase and sale agreement with The Laclede Group, Inc., pursuant to which Laclede Missouri agreed to acquire the assets of Southern Union’s MGE division and Laclede Massachusetts agreed to acquire the assets of Southern Union’s NEG division (together, the “LDC Disposal Group”). Laclede Gas Company, a subsidiary of The Laclede Group, Inc., subsequently assumed all of Laclede Missouri’s rights and obligations under the purchase and sale agreement. In February 2013, The Laclede Group, Inc. entered into an agreement with Algonquin Power & Utilities Corp (“APUC”) that allowed a subsidiary of APUC to assume the rights of The Laclede Group, Inc. to purchase the assets of Southern Union’s NEG division.

In September 2013, Southern Union completed its sale of the assets of MGE for an aggregate purchase price of $975 million, subject to customary post-closing adjustments. In December 2013, Southern Union completed its sale of the assets of NEG for cash proceeds of $40 million, subject to customary post-closing adjustments, and the assumption of $20 million of debt.

The LDC Disposal Group’s operations have been classified as discontinued operations for all periods in the consolidated statements of operations. The assets and liabilities of the LDC Disposal Group were classified as assets and liabilities held for sale at December 31, 2012.

The following table summarizes selected financial information related to Southern Union’s distribution operations in 2013 through MGE and NEG’s sale dates in September 2013 and December 2013, respectively, and for the period from March 26, 2012 to December 31, 2012:

	Years Ended December 31,	
	2013	2012
Revenue from discontinued operations	$ 415	$ 324
Net income of discontinued operations, excluding effect of taxes and overhead allocations	65	43

SUGS Contribution

On April 30, 2013, Southern Union completed its contribution to Regency of all of the issued and outstanding membership interest in Southern Union Gathering Company, LLC, and its subsidiaries, including SUGS (the "SUGS Contribution"). The general partner and IDRs of Regency are owned by ETE. The consideration paid by Regency in connection with this transaction consisted of (i) the issuance of approximately 31.4 million Regency common units to Southern Union, (ii) the issuance of approximately 6.3 million Regency Class F units to Southern Union, (iii) the distribution of $463 million in cash to Southern Union, net of closing adjustments, and (iv) the payment of $30 million in cash to a subsidiary of ETP. This transaction was between commonly controlled entities; therefore, the amounts recorded in the consolidated balance sheet for the investment in Regency and the related deferred tax liabilities were based on the historical book value of SUGS. In addition, PEPL Holdings, a wholly-owned subsidiary of Southern Union, provided a guarantee of collection with respect to the payment of the principal amounts of Regency's debt related to the SUGS Contribution. The Regency Class F units 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. The Partnership has not presented SUGS as discontinued operations due to the expected continuing involvement with SUGS through affiliate relationships, as well as the direct investment in Regency common and Class F units received, which has been accounted for using the equity method.

Acquisition of ETE's Holdco Interest

On April 30, 2013, ETP acquired ETE's 60% interest in Holdco for approximately 49.5 million of newly issued ETP Common Units and $1.40 billion in cash, less $68 million of closing adjustments (the "Holdco Acquisition"). As a result, ETP now owns 100% of Holdco. ETE, which owns the general partner and IDRs of ETP, agreed to forego incentive distributions on the newly issued ETP units for each of the first eight consecutive quarters beginning with the quarter in which the closing of the transaction occurred and 50% of incentive distributions on the newly issued ETP units for the following eight consecutive quarters. ETP controlled Holdco prior to this acquisition; therefore, the transaction did not constitute a change of control.

2012 Transactions

Southern Union Merger

On March 26, 2012, ETE completed its acquisition of Southern Union. Southern Union was the surviving entity in the merger and operated as a wholly-owned subsidiary of ETE. See below for discussion of Holdco Transaction and ETE's contribution of Southern Union to Holdco.

Under the terms of the merger agreement, Southern Union stockholders received a total of 57 million ETE Common Units and a total of approximately $3.01 billion in cash. Effective with the closing of the transaction, Southern Union's common stock was no longer publicly traded.

Citrus Acquisition

In connection with the Southern Union Merger on March 26, 2012, we completed our acquisition of CrossCountry, a subsidiary of Southern Union which owned an indirect 50% interest in Citrus, the owner of FGT. The total merger consideration was approximately $2.0 billion, consisting of approximately $1.9 billion in cash and approximately 2.2 million ETP Common Units. See Note 4 for more information regarding our equity method investment in Citrus.

Sunoco Merger

On October 5, 2012, ETP completed its merger with Sunoco. Under the terms of the merger agreement, Sunoco shareholders received 55 million ETP Common Units and a total of 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.

Prior to the Sunoco Merger, on September 8, 2012, Sunoco completed the exit from its Northeast refining operations by contributing the refining assets at its Philadelphia refinery and various commercial contracts to PES, a joint venture with The Carlyle Group. Sunoco also permanently idled the main refining processing units at its Marcus Hook refinery in June 2012. The Marcus Hook facility continued to support operations at the Philadelphia refinery prior to commencement of the PES joint venture. Under the terms of the joint venture agreement, The Carlyle Group contributed cash in exchange for a 67% controlling interest in PES. In exchange for contributing its Philadelphia refinery assets and various commercial contracts to the joint venture, Sunoco retained an approximate 33% non-operating noncontrolling interest. The fair value of Sunoco's retained interest in PES, which was $75 million on the date on which the joint venture was formed, was determined based on the equity contributions of The Carlyle Group. Sunoco has indemnified PES for environmental liabilities related to the Philadelphia refinery that arose from the operation of such assets prior the formation of the joint venture. The Carlyle Group will oversee day-to-day operations of PES and the refinery. JPMorgan Chase will provide working capital financing to PES in the form of an asset-backed loan, supply crude oil and other feedstocks to the refinery at the time of processing and purchase certain blendstocks and all finished refined products as they are processed. Sunoco entered into a supply contract for gasoline and diesel produced at the refinery for its retail marketing business.

ETP incurred merger related costs related to the Sunoco Merger of $28 million during the year ended December 31, 2012. Sunoco's revenue included in our consolidated statement of operations was approximately $5.93 billion during October through December 2012. Sunoco's net loss included in our consolidated statement of operations was approximately $14 million during October through December 2012. Sunoco Logistics' revenue included in our consolidated statement of operations was approximately $3.11 billion during October through December 2012. Sunoco Logistics' net income included in our consolidated statement of operations was approximately $145 million during October through December 2012.

Holdco Transaction

Immediately following the closing of the Sunoco Merger in 2012, 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. 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 90.7 million Class F Units representing limited partner interests in ETP ("Class F Units"). The Class F Units were exchanged for Class G Units in 2013 as discussed in Note 7. Pursuant to a stockholders agreement between ETE and ETP, ETP controlled Holdco (prior to ETP's acquisition of ETE's 60% equity interest in Holdco in 2013) and therefore, ETP consolidated Holdco (including Sunoco and Southern Union) in its financial statements subsequent to consummation of the Holdco Transaction.

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.

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).

Summary of Assets Acquired and Liabilities Assumed

We accounted for the Sunoco Merger using the acquisition method of accounting, which requires, among other things, that assets acquired and liabilities assumed be recognized on the balance sheet at their fair values as of the acquisition date. Upon consummation of the Holdco Transaction, we applied the accounting guidance for transactions between entities under common control. In doing so, we recorded the values of assets and liabilities that had been recorded by ETE as reflected below.

The following table summarizes the assets acquired and liabilities assumed as of the respective acquisition dates:

	Sunoco[1]	Southern Union[2]
Current assets	$ 7,312	$ 556
Property, plant and equipment	6,686	6,242
Goodwill	2,641	2,497
Intangible assets	1,361	55
Investments in unconsolidated affiliates	240	2,023
Note receivable	821	—
Other assets	128	163
	19,189	11,536
Current liabilities	4,424	1,348
Long-term debt obligations, less current maturities	2,879	3,120
Deferred income taxes	1,762	1,419
Other non-current liabilities	769	284
Noncontrolling interest	3,580	—
	13,414	6,171
Total consideration	5,775	5,365
Cash received	2,714	37
Total consideration, net of cash received	$ 3,061	$ 5,328

(1) Includes amounts recorded with respect to Sunoco Logistics.

(2) Includes ETP’s acquisition of Citrus.

As a result of the Holdco Transaction, we recognized $38 million of merger-related costs during the year ended December 31, 2012 related to Southern Union. Southern Union’s revenue included in our consolidated statement of operations was approximately $1.26 billion since the acquisition date to December 31, 2012. Southern Union’s net income included in our consolidated statement of operations was approximately $39 million since the acquisition date to December 31, 2012.

Propane Operations

On January 12, 2012, we contributed our propane operations, consisting of HOLP and Titan (collectively, the “Propane Business”) to AmeriGas. We received approximately $1.46 billion in cash and approximately 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 of $1.50 billion of intercompany indebtedness owed by AmeriGas to a finance subsidiary that in turn supports the repayment of $1.50 billion of senior notes issued by this AmeriGas finance subsidiary to finance the cash portion of the purchase price.

We have not reflected the Propane Business as discontinued operations as we will have a continuing involvement in this business as a result of the investment in AmeriGas that was transferred as consideration for the transaction.

In June 2012, we sold the remainder of our retail propane operations, consisting of our cylinder exchange business, to a third party. In connection with the contribution agreement with AmeriGas, certain excess sales proceeds from the sale of the cylinder exchange business were remitted to AmeriGas, and we received net proceeds of approximately $43 million.

Sale of Canyon

In October 2012, we sold Canyon for approximately $207 million. The results of continuing operations of Canyon have been reclassified to loss from discontinued operations. A write down of the carrying amounts of the Canyon assets to their fair values was recorded for approximately $132 million during the year ended December 31, 2012.

2011 Transaction

LDH Acquisition

On May 2, 2011, ETP-Regency Midstream Holdings, LLC ("ETP-Regency LLC"), a joint venture owned 70% by the Partnership and 30% by Regency, acquired all of the membership interest in LDH, from Louis Dreyfus Highbridge Energy LLC for approximately $1.98 billion in cash (the "LDH Acquisition"), including working capital adjustments. The Partnership contributed approximately $1.38 billion to ETP-Regency LLC to fund its 70% share of the purchase price. Subsequent to closing, ETP-Regency LLC was renamed Lone Star.

Lone Star owns and operates a natural gas liquids storage, fractionation and transportation business. Lone Star's storage assets are primarily located in Mont Belvieu, Texas, and its West Texas Pipeline transports NGLs through an intrastate pipeline system that originates in the Permian Basin in west Texas, passes through the Barnett Shale production area in north Texas and terminates at the Mont Belvieu storage and fractionation complex. Lone Star also owns and operates fractionation and processing assets located in Louisiana. The acquisition of LDH by Lone Star expanded the Partnership's asset portfolio by adding an NGL platform with storage, transportation and fractionation capabilities.

We accounted for the LDH Acquisition using the acquisition method of accounting. Lone Star's results of operations are included in our NGL transportation and services operations. Regency's 30% interest in Lone Star is reflected as noncontrolling interest.

4. ADVANCES TO AND INVESTMENTS IN UNCONSOLIDATED AFFILIATES:

Regency

On April 30, 2013, Southern Union completed its contribution to Regency of all of the issued and outstanding membership interest in Southern Union Gathering Company, LLC, and its subsidiaries, including SUGS (see Note 3). The consideration paid by Regency in connection with this transaction included approximately 31.4 million Regency common units, approximately 6.3 million Regency Class F units, the distribution of $463 million in cash to Southern Union, net of closing adjustments, and the payment of $30 million in cash to a subsidiary of ETP. This direct investment in Regency common and Class F units received has been accounted for using the equity method.

The carrying amount of ETP's investment in Regency was $1.41 billion as of December 31, 2013.

Citrus Corp.

On March 26, 2012, ETE consummated the acquisition of Southern Union and, concurrently with the closing of the Southern Union acquisition, CrossCountry, a subsidiary of Southern Union that indirectly owned a 50% interest in Citrus, merged with a subsidiary of ETP and, in connection therewith, ETP paid approximately $1.9 billion in cash and issued $105 million of ETP Common Units (the "Citrus Acquisition") to a subsidiary of ETE. As a result of the consummation of the Citrus Acquisition, ETP owns CrossCountry, which in turn owns a 50% interest in Citrus. The other 50% interest in Citrus is owned by a subsidiary of Kinder Morgan, Inc. Citrus owns 100% of FGT, a natural gas pipeline system that originates in Texas and delivers natural gas to the Florida peninsula.

We recorded our investment in Citrus at $2.0 billion, which exceeded our proportionate share of Citrus' equity by $1.03 billion, all of which is treated as equity method goodwill due to the application of regulatory accounting. The carrying amount of our investment in Citrus was $1.89 billion and $1.98 billion as of December 31, 2013 and 2012, respectively.

AmeriGas Partners, L.P.

As discussed in Note 3, on January 12, 2012, we received approximately 29.6 million AmeriGas common units in connection with the contribution of our propane operations. On July 12, 2013, we sold 7.5 million AmeriGas common units for net proceeds of $346 million, and as of December 31, 2013, we owned 22.1 million AmeriGas common units representing an approximate 24% limited partner interest.

The carrying amount of our investment in AmeriGas was $746 million and $1.02 billion as of December 31, 2013 and 2012, respectively. As of December 31, 2013, our investment in AmeriGas reflected $439 million in excess of our proportionate share of AmeriGas' limited partners' capital. Of this excess fair value, $184 million is being amortized over a weighted average period of 14 years, and $255 million is being treated as equity method goodwill and non-amortizable intangible assets.

In January 2014, we sold 9.2 million AmeriGas common units for net proceeds of $381 million. Net proceeds from this sale were used to repay borrowings under the ETP Credit Facility and general partnership purposes.

FEP

We have a 50% interest in FEP, a 50/50 joint venture with KMP. FEP owns the Fayetteville Express pipeline, an approximately 185-mile natural gas pipeline that originates in Conway County, Arkansas, continues eastward through White County, Arkansas and terminates at an interconnect with Trunkline Gas Company in Panola County, Mississippi. The carrying amount of our investment in FEP was $144 million and $159 million as of December 31, 2013 and 2012.

Summarized Financial Information

The following tables present aggregated selected balance sheet and income statement data for our unconsolidated affiliates, FEP, AmeriGas, Citrus and Regency (on a 100% basis) for all periods presented:

	December 31,	
	2013	2012
Current assets	$ 1,379	$ 878
Property, plant and equipment, net	12,313	8,063
Other assets	6,478	2,529
Total assets	$ 20,170	$ 11,470
Current liabilities	$ 1,455	$ 1,605
Non-current liabilities	10,286	6,143
Equity	8,429	3,722
Total liabilities and equity	$ 20,170	$ 11,470

	Years Ended December 31,		
	2013	2012	2011
Revenue	$ 6,806	$ 4,057	$ 3,337
Operating income	1,043	635	681
Net income	574	338	341

In addition to the equity method investments described above we have other equity method investments which are not significant to our consolidated financial statements.

5. DEBT OBLIGATIONS:

Our debt obligations consist of the following:

	December 31,	
	2013	2012
ETP Debt		
6.0% Senior Notes due July 1, 2013	$ —	$ 350
8.5% Senior Notes due April 15, 2014	292	292
5.95% Senior Notes due February 1, 2015	750	750
6.125% Senior Notes due February 15, 2017	400	400
6.7% Senior Notes due July 1, 2018	600	600
9.7% Senior Notes due March 15, 2019	400	400
9.0% Senior Notes due April 15, 2019	450	450
4.15% Senior Notes due October 1, 2020	700	—
4.65% Senior Notes due June 1, 2021	800	800

5.20% Senior Notes due February 1, 2022	1,000	1,000
3.60% Senior Notes due February 1, 2023	800	—
4.9% Senior Notes due February 1, 2024	350	—
7.6% Senior Notes due February 1, 2024	277	—
8.25% Senior Notes due November 15, 2029	267	—
6.625% Senior Notes due October 15, 2036	400	400
7.5% Senior Notes due July 1, 2038	550	550
6.05% Senior Notes due June 1, 2041	700	700
6.50% Senior Notes due February 1, 2042	1,000	1,000
5.15% Senior Notes due February 1, 2043	450	—
5.95% Senior Notes due October 1, 2043	450	—
Floating Rate Junior Subordinated Notes due November 1, 2066	546	—
ETP $2.5 billion Revolving Credit Facility due October 27, 2017	65	1,395
Unamortized premiums, discounts and fair value adjustments, net	(34)	(14)
	11,213	9,073
Transwestern Debt		
5.39% Senior Notes due November 17, 2014	88	88
5.54% Senior Notes due November 17, 2016	125	125
5.64% Senior Notes due May 24, 2017	82	82
5.36% Senior Notes due December 9, 2020	175	175
5.89% Senior Notes due May 24, 2022	150	150
5.66% Senior Notes due December 9, 2024	175	175
6.16% Senior Notes due May 24, 2037	75	75
Unamortized premiums, discounts and fair value adjustments, net	(1)	(1)
	869	869

Southern Union Debt [1]		
7.60% Senior Notes due February 1, 2024	82	360
8.25% Senior Notes due November 14, 2029	33	300
Floating Rate Junior Subordinated Notes due November 1, 2066	54	600
Southern Union $700 million Revolving Credit Facility due May 20, 2016	—	210
Unamortized premiums, discounts and fair value adjustments, net	48	49
	217	1,519
Panhandle Debt		
6.05% Senior Notes due August 15, 2013	—	250
6.20% Senior Notes due November 1, 2017	300	300
7.00% Senior Notes due June 15, 2018	400	400
8.125% Senior Notes due June 1, 2019	150	150
7.00% Senior Notes due July 15, 2029	66	66
Term Loan due February 23, 2015	—	455
Unamortized premiums, discounts and fair value adjustments, net	107	136
	1,023	1,757
Sunoco Debt		
4.875% Senior Notes due October 15, 2014	250	250
9.625% Senior Notes due April 15, 2015	250	250
5.75% Senior Notes due January 15, 2017	400	400
9.00% Debentures due November 1, 2024	65	65
Unamortized premiums, discounts and fair value adjustments, net	70	104
	1,035	1,069
Sunoco Logistics Debt		
8.75% Senior Notes due February 15, 2014 [2]	175	175
6.125% Senior Notes due May 15, 2016	175	175
5.50% Senior Notes due February 15, 2020	250	250
4.65% Senior Notes due February 15, 2022	300	300
3.45% Senior Notes due January 15, 2023	350	—
6.85% Senior Notes due February 15, 2040	250	250
6.10% Senior Notes due February 15, 2042	300	300
4.95% Senior Notes due January 15, 2043	350	—
Sunoco Logistics $200 million Revolving Credit Facility due August 21, 2014	—	26
Sunoco Logistics $35 million Revolving Credit Facility due April 30, 2015	35	20
Sunoco Logistics $350 million Revolving Credit Facility due August 22, 2016	—	93
Sunoco Logistics $1.50 billion Revolving Credit Facility due November 1, 2018	200	—
Unamortized premiums, discounts and fair value adjustments, net	118	143
	2,503	1,732
Note Payable to ETE	—	166
Other	228	32
	17,088	16,217
Current maturities	637	609
	$ 16,451	$ 15,608

[1] In connection with the Panhandle Merger, Southern Union's debt obligations were assumed by Panhandle.

(2) Sunoco Logistics' 8.75% Senior Notes due February 15, 2014 were classified as long-term debt as Sunoco Logistics repaid these notes in February 2014 with borrowings under its $1.50 billion credit facility due November 2018.

The following table reflects future maturities of long-term debt for each of the next five years and thereafter. These amounts exclude $308 million in unamortized net premiums and fair value adjustments:

2014	$	812
2015		1,047
2016		375
2017		1,220
2018		1,205
Thereafter		12,121
Total	$	16,780

ETP as Co-Obligor of Sunoco Debt

In connection with the Sunoco Merger and Holdco Transaction, ETP became a co-obligor on approximately $965 million of aggregate principal amount of Sunoco's existing senior notes and debentures.

ETP Senior Notes

The ETP Senior Notes were registered under the Securities Act of 1933 (as amended). The Partnership may redeem some or all of the ETP Senior Notes at any time, or from time to time, pursuant to the terms of the indenture and related indenture supplements related to the ETP Senior Notes. The balance is payable upon maturity. Interest on the ETP Senior Notes is paid semi-annually.

The ETP Senior Notes are unsecured obligations of the Partnership and the obligation of the Partnership to repay the ETP Senior Notes is not guaranteed by any of the Partnership's subsidiaries. As a result, the ETP Senior Notes effectively rank junior to any future indebtedness of ours or our subsidiaries that is both secured and unsubordinated to the extent of the value of the assets securing such indebtedness, and the ETP Senior Notes effectively rank junior to all indebtedness and other liabilities of our existing and future subsidiaries.

Transwestern Senior Notes

The Transwestern notes are payable at any time in whole or pro rata in part, subject to a premium or upon a change of control event or an event of default, as defined. The balance is payable upon maturity. Interest is paid semi-annually.

Note Payable – ETE

On March 26, 2012, Southern Union received $221 million from ETE to pay certain expenses in connection with the Merger, including (i) payments made to employees related to outstanding awards of stock options, stock appreciation rights and RSUs; and (ii) payments to certain executives under applicable employment or change in control agreements, which provided for compensation when their employment was terminated in connection with a change in control. In connection with the receipt of the $221 million from ETE, on March 26, 2012, Southern Union entered into an interest-bearing promissory note payable due on or before March 25, 2013. The interest rate under the promissory note was 3.25% and accrued interest was payable monthly in arrears. A payment of $55 million to ETE was made in May 2012, and the outstanding balance of $166 million was assumed by Holdco as of December 31, 2012 and the maturity date of the note payable was extended to January 22, 2014. The note payable outstanding was paid in 2013.

Southern Union Junior Subordinated Notes

The interest rate on the remaining portion of Southern Union's $600 million Junior Subordinated Notes due 2066 is a variable rate based upon the three-month LIBOR rate plus 3.0175%. The balance of the variable rate portion of the Junior Subordinated Notes was $600 million at an effective interest rate of 3.32% at December 31, 2013.

Panhandle Term Loans

A portion of the proceeds from ETP's September 2013 Senior Notes Offering, as discussed below, was used to repay $455 million in borrowings outstanding under the LNG Holdings term loan due February 2015.

Senior Notes Offerings

In January 2013, ETP issued $800 million aggregate principal amount of 3.6% Senior Notes due February 2023 and $450 million aggregate principal amount of 5.15% Senior Notes due February 2043. ETP used the net proceeds of $1.24 billion from the offering to repay borrowings outstanding under the ETP Credit Facility and for general partnership purposes.

In January 2013, Sunoco Logistics issued $350 million aggregate principal amount of 3.45% Senior Notes due January 2023 and $350 million aggregate principal amount of 4.95% Senior Notes due January 2043. Sunoco Logistics' used the net proceeds of $691 million from the offering to repay borrowings outstanding under the Sunoco Logistics' Credit Facilities and for general partnership purposes.

In September 2013, ETP issued $700 million aggregate principal amount of 4.15% Senior Notes due October 2020, $350 million aggregate principal amount of 4.90% Senior Notes due February 2024 and $450 million aggregate principal amount of 5.95% Senior Notes due October 2043. ETP used the net proceeds of $1.47 billion from the offering to repay $455 million in borrowings outstanding under the term loan of Panhandle's wholly-owned subsidiary, Trunkline LNG Holdings, LLC, to repay borrowings outstanding under the ETP Credit Facility and for general partnership purposes.

Note Exchange

On June 24, 2013, ETP completed the exchange of approximately $1.09 billion aggregate principal amount of Southern Union's outstanding senior notes, comprising 77% of the principal amount of the 7.6% Senior Notes due 2024, 89% of the principal amount of the 8.25% Senior Notes due 2029 and 91% of the principal amount of the Junior Subordinated Notes due 2066. These notes were exchanged for new notes issued by ETP with the same coupon rates and maturity dates. In conjunction with this transaction, Southern Union entered into intercompany notes payable to ETP, which provide for the reimbursement by Southern Union of ETP's payments under the newly issued notes.

Credit Facilities

ETP Credit Facility

The ETP Credit Facility allows for borrowings of up to $2.5 billion and expires in October 2017. The indebtedness under the ETP Credit Facility is unsecured and not guaranteed by any of the ETP'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. The ETP Credit Facility provides temporary financing for growth projects, as well as for general partnership purposes.

In November 2013, ETP amended the ETP Credit Facility to, among other things, (i) extend the maturity date for one additional year to October 2017, (ii) remove the restriction prohibiting unrestricted subsidiaries from owning debt or equity interests in ETP or any restricted subsidiaries of ETP, (iii) amend the covenant limiting fundamental changes to remove the restrictions on mergers or other consolidations of restricted subsidiaries of ETP and to permit ETP to merge with another person and not be the surviving entity provided certain requirements are met, and (iv) amend certain other provisions more specifically set forth in the amendment.

As of December 31, 2013, the ETP Credit Facility had $65 million outstanding, and the amount available for future borrowings was $2.34 billion after taking into account letters of credit of $93 million. The weighted average interest rate on the total amount outstanding as of December 31, 2013 was 1.67%.

Southern Union Credit Facility

Proceeds from the SUGS Contribution were used to repay borrowings under the Southern Union Credit Facility and the facility was terminated.

Sunoco Logistics Credit Facilities

In November 2013, Sunoco Logistics replaced its existing $350 million and $200 million unsecured credit facilities with a new $1.50 billion unsecured credit facility (the "$1.50 billion Credit Facility"). The $1.50 billion Credit Facility contains an accordion feature, under which the total aggregate commitment may be extended to $2.25 billion under certain conditions. Outstanding borrowings under the $350 million and $200 million credit facilities of $119 million at December 31, 2012 were repaid during the first quarter of 2013.

The $1.50 billion Credit Facility, which matures in November 2018, is available to fund Sunoco Logistics' working capital requirements, to finance acquisitions and capital projects, to pay distributions and for general partnership purposes. The $1.50

billion Credit Facility bears interest at LIBOR or the Base Rate, each plus an applicable margin. The credit facility may be prepaid at any time. Outstanding borrowings under this credit facility were $200 million at December 31, 2013.

West Texas Gulf Pipe Line Company, a subsidiary of Sunoco Logistics, has a $35 million revolving 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 $35 million at December 31, 2013.

Covenants Related to Our Credit Agreements

Covenants Related to ETP

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.

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 assets and the payment of dividends and specify a maximum debt to capitalization ratio.

Failure to comply with the various restrictive and affirmative covenants of our revolving credit facilities could require us to pay debt balances prior to scheduled maturity and could negatively impact the Operating Companies' ability to incur additional debt and/or our ability to pay distributions.

Covenants Related to Southern Union

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 that require Southern Union to maintain a certain level of net worth, to meet certain debt to total capitalization ratios and to meet certain ratios of earnings before depreciation, interest and taxes to cash interest expense. 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.

In addition, 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 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

Sunoco Logistics' $1.50 billion credit facility contains various covenants, including limitations on the creation of indebtedness and liens, and other covenants related to the operation and conduct of the business of Sunoco Logistics and its subsidiaries. The credit facility also limits Sunoco Logistics, on a rolling four-quarter basis, to a maximum total consolidated debt to consolidated Adjusted EBITDA ratio, as defined in the underlying credit agreement, of 5.0 to 1, which can generally be increased to 5.5 to 1 during an acquisition period. Sunoco Logistics' ratio of total consolidated debt, excluding net unamortized fair value adjustments, to consolidated Adjusted EBITDA was 2.8 to 1 at December 31, 2013, as calculated in accordance with the credit agreements.

The $35 million credit facility 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, 2013 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 1.12 to 1 and 0.88 to 1, respectively, at December 31, 2013.

We were in compliance with all requirements, tests, limitations, and covenants related to our debt agreements as of December 31, 2013.

6. EQUITY:

Limited Partner interests are represented by Class A Units and Class B Units that entitle the holders thereof to the rights and privileges specified in the Partnership Agreement. The Class B Units constitute a profits interest in ETP GP and will only receive allocations of income, gain, loss deduction and credit and their pro rata share of cash distributions from ETP GP attributable to the ownership of ETP's IDRs. Under our Partnership Agreement, after giving effect to the special allocation of net income to our Class B Units for their profits interest, net income is allocated among the Partners as follows:

- First, 100% to our General Partner, until the aggregate net income allocated to our General Partner for the current year and all previous years is equal to the aggregate net losses allocated to our General Partner for all previous years;
- Second, 99.99% to our Class A Limited Partners, in proportion to their relative allocation of net losses, and 0.01% to our General Partner until the aggregate net income allocated to our Class A Limited Partners and our General Partner for the current and all previous years is equal to the aggregate net losses allocated to our Class A Limited Partners and our General Partner for all previous years; and
- Third, 99.99% to our Class A Limited Partners, pro rata, and 0.01% to our General Partner.

Common Units Activity by ETP

The change in ETP Common Units was as follows:

	Years Ended December 31,		
	2013	2012	2011
Number of Common Units, beginning of period	301.5	225.5	193.2
Common Units issued in connection with public offerings	13.8	15.5	29.4
Common Units issued in connection with certain acquisitions	49.5	57.4	0.1
Common Units redeemed for Class H Units	(50.2)	—	—
Common Units issued in connection with the Distribution Reinvestment Plan	2.3	1.0	0.4
Common Units issued in connection with Equity Distribution Agreements	16.9	1.6	2.0
Repurchase of Common units in open-market transactions	(0.4)	—	—
Issuance of Common Units under equity incentive plans	0.4	0.5	0.4
Number of Common Units, end of period	333.8	301.5	225.5

ETP's Common Units are registered under the Securities Exchange Act of 1934 (as amended) and are listed for trading on the NYSE. Each holder of an ETP Common Unit is entitled to one vote per unit on all matters presented to the ETP Limited Partners for a vote. In addition, if at any time any person or group (other than ETP's General Partner and its affiliates) owns beneficially 20% or more of all ETP Common Units, any ETP Common Units owned by that person or group may not be voted on any matter and are not considered to be outstanding when sending notices of a meeting of ETP Unitholders (unless otherwise required by law), calculating required votes, determining the presence of a quorum or for other similar purposes under the Partnership Agreement. The ETP Common Units are entitled to distributions of Available Cash as described below under "Quarterly Distributions of Available Cash."

ETP Class G Units

In conjunction with the Sunoco Merger, ETP amended their partnership agreement to create the ETP Class F Units. The number of ETP Class F Units issued was determined at the closing of the Sunoco Merger and equaled 90.7 million, which included 40 million ETP 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 ETP Class F Units generally did not have any voting rights. The ETP Class F Units were entitled to aggregate cash distributions equal to 35% of the total amount of cash generated by ETP and its subsidiaries, other than Holdco, and available for distribution, up to a maximum of $3.75 per Class F Unit per year. In April 2013, all of the outstanding ETP Class F Units were exchanged for ETP Class G Units on a one-for-one basis. The ETP Class G Units have terms that are substantially the same as the ETP Class F Units, with the principal difference between the ETP Class G Units and the ETP Class F Units being that allocations of depreciation and amortization to the ETP Class G Units for tax purposes are based on a predetermined percentage and are not contingent on whether ETP has net income or loss.

ETP Class H Units

Pursuant to an Exchange and Redemption Agreement previously entered into between ETP, ETE and ETE Holdings, ETP redeemed and cancelled 50.2 million ETP Common Units representing limited partner interests (the "Redeemed Units") owned by ETE Holdings on October 31, 2013 in exchange for the issuance by ETP to ETE Holdings of a new class of limited partner interest in ETP (the "ETP Class H Units"), which are generally entitled to (i) allocations of profits, losses and other items from ETP corresponding to 50.05% of the profits, losses, and other items allocated to ETP by Sunoco Partners with respect to the IDRs and general partner interest in Sunoco Logistics held by Sunoco Partners, (ii) distributions from available cash at ETP for each quarter equal to 50.05% of the cash distributed to ETP by Sunoco Partners with respect to the IDRs and general partner interest in Sunoco Logistics held by Sunoco Partners for such quarter and, to the extent not previously distributed to holders of the ETP Class H Units, for any previous quarters and (iii) incremental additional cash distributions in the aggregate amount of $329 million, to be payable by ETP to ETE Holdings over 15 quarters, commencing with the quarter ended September 30, 2013 and ending with the quarter ending March 31, 2017. The incremental cash distributions referred to in clause (iii) of the previous sentence are intended to offset a portion of the IDR subsidies previously granted by ETE to ETP in connection with the Citrus Merger, the Holdco Transaction and the Holdco Acquisition. In connection with the issuance of the ETP Class H Units, ETE and ETP also agreed to certain adjustments to the prior IDR subsidies in order to ensure that the IDR subsidies are fixed amounts for each quarter to which the IDR subsidies are in effect. For a summary of the net IDR subsidy amounts resulting from this transaction, see "Quarterly Distributions of Available Cash" below.

Sale of Common Units by ETP

The following table summarizes ETP's public offerings of Common Units, all of which have been registered under the Securities Act of 1933 (as amended):

Date	Number of Common Units	Price per Unit	Net Proceeds
April 2011	14.2	$ 50.52	$ 695
November 2011	15.2	44.67	660
July 2012	15.5	44.57	671
April 2013	13.8	48.05	657

Proceeds from the offerings listed above were used to repay amounts outstanding under the ETP Credit Facility and/or to fund capital expenditures and capital contributions to joint ventures, and for general partnership purposes.

ETP's Equity Distribution Program

From time to time, ETP has sold Common Units through an equity distribution agreement. Such sales of ETP Common Units are made by means of ordinary brokers' transactions on the NYSE at market prices, in block transactions or as otherwise agreed between ETP and the sales agent which is the counterparty to the equity distribution agreement.

In January 2013 and May 2013, ETP entered into equity distribution agreements pursuant to which ETP may sell from time to time ETP Common Units having aggregate offering prices of up to $200 million and $800 million, respectively. During the year ended December 31, 2013, ETP issued approximately 16.9 million units for $846 million, net of commissions of $9 million. Approximately $145 million of ETP's Common Units remained available to be issued under the currently effective equity distribution agreements as of December 31, 2013.

Quarterly Distribution of Available Cash

Our distributions policy is consistent with the terms of the Partnership Agreement, which require that we distribute all of our available cash quarterly. Our only cash-generating assets consist of partnership interests, including IDRs, from which we receive quarterly distributions from ETP. We have no independent operations outside of our interests in ETP. Under the Partnership Agreement, our distributions are characterized as the GP Distribution Amount and the IDR Distribution Amount. The GP Distribution Amount is all distributions we receive from ETP with respect to our General Partner Interest and the IDR Distribution Amount is all distributions received from ETP with respect to the IDR. Within 45 days following the end of each quarter, we will distribute all of our GP Available Cash and IDR Available Cash, as defined in the Partnership Agreement. GP Available Cash shall be distributed 99.99% to the Class A Limited Partners, pro rata and 0.01% to the General partner. IDR Available Cash shall be distributed 99.99% to the Class B Limited Partners, pro rata and 0.01% to the General Partner.

ETP GP has the right, in connection with the issuance of any equity security by ETP, to purchase equity securities on the same terms as these equity securities are issued to third parties sufficient to enable ETP GP and its affiliates to maintain the aggregate percentage equity interest in ETP as ETP GP and its affiliates owned immediately prior to such issuance.

Contributions to Subsidiary

The Parent Company indirectly owns the entire general partner interest in ETP through its ownership of ETP GP, the general partner of ETP. ETP GP has the right, but not the obligation, to contribute a proportionate amount of capital to ETP to maintain its current general partner interest. ETP GP's interest in ETP's distributions is reduced if ETP issues additional units and ETP GP does not contribute a proportionate amount of capital to ETP to maintain its General Partner interest.

ETP's Quarterly Distributions of Available Cash

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

ETP's distributions of Available Cash from operating surplus, excluding incentive distributions, to our General Partner and Limited Partner interests are based on their respective interests as of the distribution record date. Incentive distributions allocated to the General Partner are determined based on the amount by which quarterly distribution to ETP common Unitholders exceed certain specified target levels, as set forth in the ETP Partnership Agreement.

ETP distributions declared during the periods presented below are summarized as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2010	February 7, 2011	February 14, 2011	$ 0.89375
March 31, 2011	May 6, 2011	May 16, 2011	0.89375
June 30, 2011	August 5, 2011	August 15, 2011	0.89375
September 30, 2011	November 4, 2011	November 14, 2011	0.89375
December 31, 2011	February 7, 2012	February 14, 2012	0.89375
March 31, 2012	May 4, 2012	May 15, 2012	0.89375
June 30, 2012	August 6, 2012	August 14, 2012	0.89375
September 30, 2012	November 6, 2012	November 14, 2012	0.89375
December 31, 2012	February 7, 2013	February 14, 2013	0.89375
March 31, 2013	May 6, 2013	May 15, 2013	0.89375
June 30, 2013	August 5, 2013	August 14, 2013	0.89375
September 30, 2013	November 4, 2013	November 14, 2013	0.90500
December 31, 2013	February 7, 2014	February 14, 2014	0.92000

Following are incentive distributions ETE has agreed to relinquish:

- In conjunction with the Partnership's Citrus Merger, ETE agreed to relinquish its rights to $220 million of incentive distributions from ETP that ETE would otherwise be entitled to receive over 16 consecutive quarters beginning with the distribution paid on May 15, 2012.
- In conjunction with the Holdco Transaction in October 2012, 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.
- As discussed in Note 3, in connection with the Holdco Acquisition on April 30, 2013, ETE also agreed to relinquish incentive distributions on the newly issued Common Units for the first eight consecutive quarters beginning with the distribution paid on August 14, 2013, and 50% of the incentive distributions for the following eight consecutive quarters.

In addition, the incremental distributions on the ETP Class H Units, which are referred to in "ETP Class H Units" above, were intended to offset a portion of the incentive distribution relinquishments previously granted by ETE to ETP. In connection with the issuance of the ETP Class H Units, ETE and ETP also agreed to certain adjustments to the incremental distributions on the ETP Class H Units in order to ensure that the net impact of the incentive distribution relinquishments (a portion of which is variable) and the incremental distributions on the ETP Class H Units are fixed amounts for each quarter for which the incentive distribution relinquishments and incremental distributions on the ETP Class H Units are in effect.

In addition to the amounts above, in connection with the ETP's transfer of Trunkline LNG to ETE in February 2014, ETE agreed to provide additional subsidies to ETP through its relinquishment of IDRs in $50 million, $50 million, $45 million and $35 million for the years ending December 31, 2016, 2017, 2018 and 2019, respectively.

Following is a summary of the net amounts by which these incentive distribution relinquishments and incremental distributions on ETP Class H Units would reduce the total distributions that would potentially be made to ETE in future quarters:

	Quarters Ending				
	March 31	June 30	September 30	December 31	Total Year
2014	$ 26.5	$ 26.5	$ 26.5	$ 26.5	$ 106.0
2015	12.5	12.5	13.0	13.0	51.0
2016	18.0	18.0	18.0	18.0	72.0
2017	12.5	12.5	12.5	12.5	50.0
2018	11.25	11.25	11.25	11.25	45.0
2019	8.75	8.75	8.75	8.75	35.0

Sunoco Logistics Quarterly Distributions of Available Cash

Distributions declared during the periods presented below are summarized as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2012	February 8, 2013	February 14, 2013	$ 0.54500
March 31, 2013	May 9, 2013	May 15, 2013	0.57250
June 30, 2013	August 8, 2013	August 14, 2013	0.60000
September 30, 2013	November 8, 2013	November 14, 2013	0.63000
December 31, 2013	February 10, 2014	February 14, 2014	0.66250

Accumulated Other Comprehensive Income (Loss)

The following table presents the components of AOCI, net of tax:

	December 31,	
	2013	2012
Available-for-sale securities	$ 2	$ —
Foreign currency translation adjustment	(1)	—
Net loss on commodity related hedges	(4)	—
Actuarial gain (loss) related to pensions and other postretirement benefits	56	(10)
Equity investments, net	8	(9)
Subtotal	61	(19)
Amounts attributable to noncontrolling interest	(61)	19
Total AOCI, net of tax	$ —	$ —

7. UNIT-BASED COMPENSATION PLANS:

ETP Unit-Based Compensation Plan

ETP has issued equity incentive plans for employees, officers and directors, which provide for various types of awards, including options to purchase ETP Common Units, restricted units, phantom units, distribution equivalent rights ("DERs"), Common Unit appreciation rights, and other unit-based awards. As of December 31, 2013, an aggregate total of 0.9 million ETP Common Units remain available to be awarded under its equity incentive plans.

ETP Unit Grants

ETP has granted restricted unit awards to employees that vest over a specified time period, typically a five-year service vesting requirement, with vesting contingent on continued employment as of each applicable vesting date. Upon vesting, ETP Common Units are issued. 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 ETP Common Unit made by ETP on its common units promptly following each such distribution by ETP to its unitholders. These rights as "distribution equivalent rights." Under ETP's equity incentive plans, ETP's non-employee directors each receive grants with a five-year service vesting requirement.

Award Activity

The following table shows the activity of the awards granted to employees and non-employee directors:

	Number of Units	Weighted Average Grant-Date Fair Value Per Unit
Unvested awards as of December 31, 2012	1.9	$ 46.95
Awards granted	2.1	50.54
Awards vested	(0.6)	45.62
Awards forfeited	(0.2)	45.72
Unvested awards as of December 31, 2013	3.2	49.65

During the years ended December 31, 2013, 2012 and 2011, the weighted average grant-date fair value per unit award granted was $50.54, $43.93 and $48.35, respectively. The total fair value of awards vested was $26 million, $29 million and $27 million, respectively, based on the market price of ETP Common Units as of the vesting date. As of December 31, 2013, a total of 3.2 million unit awards remain unvested, for which ETP expects to recognize a total of $116 million in compensation expense over a weighted average period of 2.1 years.

Sunoco Logistics' Unit-Based Compensation Plan

Sunoco Logistics' general partner has a long-term incentive plan for employees and directors, which permits the grant of restricted units and unit options of Sunoco Logistics covering an additional 0.6 million Sunoco common units. As of December 31, 2013, a total of 0.6 million Sunoco Logistics restricted units were outstanding for which Sunoco Logistics expects to recognize $21 million of expense over a weighted-average period of 2.8 years.

Related Party Awards

McReynolds Energy Partners, L.P., the general partner of which is owned and controlled by the President of the entity that indirectly owns our general partner, awarded to certain officers of ETP certain rights related to units of ETE previously issued by ETE to such ETE officer. These rights include the economic benefits of ownership of these ETE units based on a 5 year vesting schedule whereby the officer vested in the ETE units at a rate of 20% per year. As these ETE units 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 were paid by ETP or ETE. As these units were outstanding prior to these awards, these awards did not represent an increase in the number of outstanding units of either ETP or ETE and were not dilutive to cash distributions per unit with respect to either ETP or ETE.

We recognized 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. For the years ended December 31, 2013, 2012 and 2011, we recognized non-cash compensation expense, net of forfeitures, of less than $1 million, $1 million and $2 million, respectively, as a result of these awards. As of December 31, 2013, no rights related to ETE common units remain outstanding.

8. INCOME TAXES:

As a partnership, we are not subject to U.S. federal income tax and most state income taxes. However, the partnership conducts certain activities through corporate subsidiaries which are subject to federal and state income taxes. The components of the federal and state income tax expense (benefit) are summarized as follows:

	Years Ended December 31,		
	2013	2012	2011
Current expense (benefit):			
Federal	$ 51	$ (3)	$ (1)
State	(2)	4	16
Total	49	1	15
Deferred expense:			
Federal	(6)	45	4
State	54	17	—
Total	48	62	4
Total income tax expense from continuing operations	$ 97	$ 63	$ 19

Historically, our effective rate differed from the statutory rate primarily due to Partnership earnings that are not subject to U.S. federal and most state income taxes at the Partnership level. The completion of the Southern Union Merger, Sunoco Merger and Holdco Transaction (see Note 3) significantly increased the activities conducted through corporate subsidiaries. A reconciliation of income tax expense (benefit) at the U.S. statutory rate to the income tax expense (benefit) attributable to continuing operations for the years ended December 31, 2013 and 2012 is as follows:

	December 31, 2013			December 31, 2012		
	Corporate Subsidiaries(1)	Partnership(2)	Consolidated	Corporate Subsidiaries(1)	Partnership(2)	Consolidated
Income tax expense (benefit) at U.S. statutory rate of 35 percent	$ (166)	$ —	$ (166)	$ 1	$ —	$ 1
Increase (reduction) in income taxes resulting from:						
Nondeductible goodwill	241	—	241	—	—	—
Nondeductible executive compensation	—	—	—	28	—	28
State income taxes (net of federal income tax effects)	31	5	36	9	7	16
Other	(13)	(1)	(14)	18	—	18
Income tax from continuing operations	$ 93	$ 4	$ 97	$ 56	$ 7	$ 63

(1) Includes Holdco, Oasis Pipeline Company, Inland Corporation, Mid-Valley Pipeline Company and West Texas Gulf Pipeline Company. The latter three entities were acquired in the Sunoco Merger. Holdco, which was formed via the Sunoco Merger and the Holdco Transaction (see Note 3), includes Sunoco and Southern Union and their subsidiaries. ETE held a 60% interest in Holdco until April 30, 2013. Subsequent to the Holdco Acquisition (see Note 3) on April 30, 2013, ETP owns 100% of Holdco.

(2) Includes ETP and its subsidiaries that are classified as pass-through entities for federal income tax purposes.

Deferred taxes result from the temporary differences between financial reporting carrying amounts and the tax basis of existing assets and liabilities. The table below summarizes the principal components of the deferred tax assets (liabilities) as follows:

	December 31,	
	2013	2012
Deferred income tax assets:		
Net operating losses and alternative minimum tax credit	$ 217	$ 268
Pension and other postretirement benefits	57	127
Long term debt	108	117
Other	104	288
Total deferred income tax assets	486	800
Valuation allowance	(74)	(90)
Net deferred income tax assets	$ 412	$ 710
Deferred income tax liabilities:		
Properties, plants and equipment	$ (1,522)	$ (1,938)
Inventory	(302)	(516)
Investment in unconsolidated affiliates	(2,244)	(1,542)
Trademarks	(180)	(192)
Other	(45)	(128)
Total deferred income tax liabilities	(4,293)	(4,316)
Net deferred income tax liability	(3,881)	(3,606)
Less: current portion of deferred income tax assets (liabilities)	(119)	(130)
Accumulated deferred income taxes	$ (3,762)	$ (3,476)

The completion of the Southern Union Merger, Sunoco Merger and Holdco Transaction (see Note 3) significantly increased the deferred tax assets (liabilities). The table below provides a rollforward of the net deferred income tax liability as follows:

	December 31,	
	2013	2012
Net deferred income tax liability, beginning of year	$ (3,606)	$ (123)
Southern Union acquisition	—	(1,420)
Sunoco acquisition	—	(1,989)
SUGS Contribution to Regency	(115)	—
Tax provision (including discontinued operations)	(111)	(73)
Other	(49)	(1)
Net deferred income tax liability	$ (3,881)	$ (3,606)

Holdco and other corporate subsidiaries have gross federal net operating loss carryforwards of $216 million, all of which will expire in 2032. Holdco has $40 million of federal alternative minimum tax credits which do not expire. Holdco and other corporate subsidiaries have state net operating loss carryforward benefits of $101 million, net of federal tax, which expire between 2013 and 2032. The valuation allowance of $74 million is applicable to the state net operating loss carryforward benefits applicable to Sunoco pre-acquisition periods.

The following table sets forth the changes in unrecognized tax benefits:

	Years Ended December 31,		
	2013	2012	2011
Balance at beginning of year	$ 27	$ 2	$ 2
Additions attributable to acquisitions	—	28	—
Additions attributable to tax positions taken in the current year	—	—	1
Additions attributable to tax positions taken in prior years	406	—	—
Settlements	—	—	(1)
Lapse of statute	(4)	(3)	—
Balance at end of year	$ 429	$ 27	$ 2

As of December 31, 2013, we have $425 million ($418 million after federal income tax benefits) related to tax positions which, if recognized, would impact our effective tax rate. We believe it is reasonably possible that its unrecognized tax benefits may be reduced by $6 million ($5 million, net of federal tax) within the next twelve months due to settlement of certain positions.

Sunoco has historically included certain government incentive payments as taxable income on its federal and state income tax returns. In connection with Sunoco's 2004 through 2011 open statute years, Sunoco has proposed to the IRS that these government incentive payments be excluded from federal taxable income. If Sunoco is fully successful with its claims, it will receive tax refunds of approximately $372 million. However, due to the uncertainty surrounding the claims, a reserve of $372 million was established for the full amount of the claims. Due to the timing of the expected settlement of the claims and the related reserve, the receivable and the reserve for this issue have been netted in the financial statements as of December 31, 2013.

Our policy is to accrue interest expense and penalties on income tax underpayments (overpayments) as a component of income tax expense. During 2013, we recognized interest and penalties of less than $1 million. At December 31, 2013, we have interest and penalties accrued of $6 million, net of tax.

In general, ETP and its subsidiaries are no longer subject to examination by the IRS for tax years prior to 2009, except Sunoco and Southern Union which are no longer subject to examination by the IRS for tax years prior to 2007 and 2004, respectively.

Sunoco has been examined by the IRS for the 2007 and 2008 tax years; however, the statutes remain open for both of these tax years due to carryback of net operating losses. Sunoco is currently under examination for the years 2009 through 2011, but due to the aforementioned carryback, such years also impact Sunoco's tax liability for the years 2004 through 2008. With the exception of the claims regarding government incentive payments discussed above, all issues are resolved. Southern Union is under examination for the tax years 2004 through 2009. As of December 31, 2013, the IRS has proposed only one adjustment for the years under examination. For the 2006 tax year, the IRS is challenging $545 million of the $690 million of deferred gain associated with a like kind exchange involving certain assets of its distribution operations and its gathering and processing operations. We will vigorously defend and believe Southern Union's tax position will prevail against this challenge by the IRS. Accordingly, no unrecognized tax benefit has been recorded with respect to this tax position.

ETP and its subsidiaries also have various state and local income tax returns in the process of examination or administrative appeal in various jurisdictions. We believe the appropriate accruals or unrecognized tax benefits have been recorded for any potential assessment with respect to these examinations.

9. REGULATORY MATTERS, COMMITMENTS, CONTINGENCIES AND ENVIRONMENTAL LIABILITIES:

FERC Audit

The FERC recently completed an audit of PEPL, a subsidiary of Southern Union, for the period from January 1, 2010 through December 31, 2011, to evaluate its compliance with the Uniform System of Accounts as prescribed by the FERC, annual and quarterly financial reporting to the FERC, reservation charge crediting policy and record retention. An audit report was received in August 2013 noting no issues that would have a material impact on the Partnership's historical financial position or results of operations.

Contingent Matters Potentially Impacting the Partnership from Our Investment in Citrus

Florida Gas Pipeline Relocation Costs. The Florida Department of Transportation, Florida's Turnpike Enterprise ("FDOT/FTE") has various turnpike/State Road 91 widening projects that have impacted or may, over time, impact one or more of FGTs' mainline pipelines located in FDOT/FTE rights-of-way. Certain FDOT/FTE projects have been or are the subject of litigation in Broward County, Florida. On November 16, 2012, FDOT paid to FGT the sum of approximately $100 million, representing the amount of the judgment, plus interest, in a case tried in 2011.

On April 14, 2011, FGT filed suit against the FDOT/FTE and other defendants in Broward County, Florida seeking an injunction and damages as the result of the construction of a mechanically stabilized earth wall and other encroachments in FGT easements as part of FDOT/FTE's I-595 project. On August 21, 2013, FGT and FDOT/FTE entered into a settlement agreement pursuant to which, among other things, FDOT/FTE paid FGT approximately $19 million in September, 2013 in settlement of FGT's claims with respect to the I-595 project. The settlement agreement also provided for agreed easement widths for FDOT/FTE right-of-way and for cost sharing between FGT and FDOT/FTE for any future relocations. Also in September 2013, FDOT/FTE paid FGT an additional approximate $1 million for costs related to the aforementioned turnpike/State Road 91 case tried in 2011.

FGT will continue to seek rate recovery in the future for these types of costs to the extent not reimbursed by the FDOT/FTE. There can be no assurance that FGT will be successful in obtaining complete reimbursement for any such relocation costs from the FDOT/FTE or from its customers or that the timing of such reimbursement will fully compensate FGT for its costs.

Contingent Residual Support Agreement – AmeriGas

In connection with the closing of the contribution of its propane operations in January 2012, ETP agreed to provide contingent, residual support of $1.55 billion of intercompany borrowings made by AmeriGas and certain of its affiliates with maturities through 2022 from a finance subsidiary of AmeriGas that have maturity dates and repayment terms that mirror those of an equal principal amount of senior notes issued by this finance company subsidiary to third party purchases.

PEPL Holdings Guarantee of Collection

In connection with the SUGS Contribution, Regency issued $600 million of 4.50% Senior Notes due 2023 (the "Regency Debt"), the proceeds of which were used by Regency to fund the cash portion of the consideration, as adjusted, and pay certain other expenses or disbursements directly related to the closing of the SUGS Contribution. In connection with the closing of the SUGS Contribution on April 30, 2013, Regency entered into an agreement with PEPL Holdings, a subsidiary of Southern Union, pursuant to which PEPL Holdings provided a guarantee of collection (on a nonrecourse basis to Southern Union) to Regency and Regency Energy Finance Corp. with respect to the payment of the principal amount of the Regency Debt through maturity in 2023. In connection with the completion of the Panhandle Merger, in which PEPL Holdings was merged with and into Panhandle, the guarantee of collection for the Regency Debt was assumed by Panhandle.

NGL Pipeline Regulation

We have interests in NGL pipelines located in Texas and New Mexico. We commenced the interstate transportation of NGLs in 2013, which is subject to the jurisdiction of the FERC under the ICA and the Energy Policy Act of 1992. Under the ICA, tariffs must be just and reasonable and not unduly discriminatory or confer any undue preference. The tariff rates established for interstate services were based on a negotiated agreement; however, the FERC's rate-making methodologies may limit our ability to set rates based on our actual costs, may delay or limit the use of rates that reflect increased costs and may subject us to potentially burdensome and expensive operational, reporting and other requirements. Any of the foregoing could adversely affect our business, revenues and cash flow.

Commitments

In the normal course of our business, we purchase, process and sell natural gas pursuant to long-term contracts and we enter into long-term transportation and storage agreements. Such contracts contain terms that are customary in the industry. We believe that the terms of these agreements are commercially reasonable and will not have a material adverse effect on our financial position or results of operations.

We have certain non-cancelable leases for property and equipment, which require fixed monthly rental payments and expire at various dates through 2056. Rental expense under these operating leases has been included in operating expenses in the accompanying statements of operations and totaled approximately $140 million, $57 million and $26 million for the years ended December 31, 2013, 2012 and 2011, respectively, which include contingent rentals totaling $22 million and $6 million in 2013 and 2012, respectively. During the years ended December 31, 2013 and 2012, approximately $24 million and $4 million, respectively, of rental expense was recovered through related sublease rental income.

Future minimum lease commitments for such leases are:

Years Ending December 31:		
2014	$	80
2015		78
2016		70
2017		66
2018		53
Thereafter		42
Future minimum lease commitments		389
Less: Sublease rental income		(57)
Net future minimum lease commitments	$	332

Our joint venture agreements require that we fund our proportionate share of capital contributions to our unconsolidated affiliates. Such contributions will depend upon our unconsolidated affiliates' capital requirements, such as for funding capital projects or repayment of long-term obligations.

Litigation and Contingencies

We may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business. Natural gas and crude are flammable and combustible. Serious personal injury and significant property damage can arise in connection with their transportation, storage or use. In the ordinary course of business, we are sometimes threatened with or named as a defendant in various lawsuits seeking actual and punitive damages for product liability, personal injury and property damage. We maintain liability insurance with insurers in amounts and with coverage and deductibles management believes are reasonable and prudent, and which are generally accepted in the industry. However, there can be no assurance that the levels of insurance protection currently in effect will continue to be available at reasonable prices or that such levels will remain adequate to protect us from material expenses related to product liability, personal injury or property damage in the future.

Sunoco Litigation

Following the announcement of the Sunoco Merger on April 30, 2012, eight putative class action and derivative complaints were filed in connection with the Sunoco Merger in the Court of Common Pleas of Philadelphia County, Pennsylvania. Each complaint names as defendants the members of Sunoco's board of directors and alleges that they breached their fiduciary duties by negotiating and executing, through an unfair and conflicted process, a merger agreement that provides inadequate consideration and that contains impermissible terms designed to deter alternative bids. Each complaint also names as defendants Sunoco, ETP, ETP GP, ETP LLC, and Sam Acquisition Corporation, alleging that they aided and abetted the breach of fiduciary duties by Sunoco's directors; some of the complaints also name ETE as a defendant on those aiding and abetting claims. In September 2012, all of these lawsuits were settled with no payment obligation on the part of any of the defendants following the filing of Current Reports on Form 8-K that included additional disclosures that were incorporated by reference into the proxy statement related to the Sunoco Merger. Subsequent to the settlement of these cases, the plaintiffs' attorneys sought compensation from Sunoco for attorneys' fees related to their efforts in obtaining these additional disclosures. In January 2013, Sunoco entered into agreements to compensate the plaintiffs' attorneys in the state court actions in the aggregate amount of not more than $950,000 and to compensate the plaintiffs' attorneys in the federal court action in the amount of not more than $250,000. The payment of $950,000 was made in July 2013.

Litigation Relating to the Southern Union Merger

In June 2011, several putative class action lawsuits were filed in the Judicial District Court of Harris County, Texas naming as defendants the members of the Southern Union Board, as well as Southern Union and ETE. The lawsuits were styled *Jaroslawicz v. Southern Union Company, et al.*, Cause No. 2011-37091, in the 333rd Judicial District Court of Harris County, Texas and *Magda v. Southern Union Company, et al.*, Cause No. 2011-37134, in the 11th Judicial District Court of Harris County, Texas. The lawsuits were consolidated into an action styled *In re: Southern Union Company*; Cause No. 2011-37091, in the 333rd Judicial District Court of Harris County, Texas. Plaintiffs allege that the Southern Union directors breached their fiduciary duties to Southern Union's stockholders in connection with the Merger and that Southern Union and ETE aided and abetted the alleged breaches of fiduciary duty. The amended petitions allege that the Merger involves an unfair price and an inadequate sales process, that Southern Union's directors entered into the Merger to benefit themselves personally, including through consulting and noncompete agreements, and that defendants have failed to disclose all material information related to the Merger to Southern Union stockholders. The amended petitions seek injunctive relief, including an injunction of the Merger, and an award of attorneys' and other fees and costs, in addition to other relief. On October 21, 2011, the court denied ETE's October 13, 2011, motion to stay the Texas proceeding in favor of cases pending in the Delaware Court of Chancery.

Also in June 2011, several putative class action lawsuits were filed in the Delaware Court of Chancery naming as defendants the members of the Southern Union Board, as well as Southern Union and ETE. Three of the lawsuits also named Merger Sub as a defendant. These lawsuits are styled: *Southeastern Pennsylvania Transportation Authority, et al. v. Southern Union Company, et al.*, C.A. No. 6615-CS; *KBC Asset Management NV v. Southern Union Company, et al.*, C.A. No. 6622-CS; *LBBW Asset Management Investment GmbH v. Southern Union Company, et al.*, C.A. No. 6627-CS; and *Memo v. Southern Union Company, et al.*, C.A. No. 6639-CS. These cases were consolidated with the following style: *In re Southern Union Co. Shareholder Litigation*, C.A. No. 6615-CS, in the Delaware Court of Chancery. The consolidated complaint asserts similar claims and allegations as the Texas state-court consolidated action. On July 25, 2012, the Delaware plaintiffs filed a notice of voluntary dismissal of all claims without prejudice. In the notice, plaintiffs stated their claims were being dismissed to avoid duplicative litigation and indicated their intent to join the Texas case.

On September 18, 2013, the plaintiff dismissed without prejudice its lawsuit against all defendants.

MTBE Litigation

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 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 also seek natural resource damages, injunctive relief, punitive damages and attorneys' fees.

As of December 31, 2013, Sunoco is a defendant in seven cases, one of which was initiated by the State of New Jersey and two others by the Commonwealth of Puerto Rico with the more recent Puerto Rico action being a companion case alleging damages for additional sites beyond those at issue in the initial Puerto Rico action. Six of these cases are venued in a multidistrict litigation ("MDL") proceeding in a New York federal court. The most recently filed Puerto Rico action is expected to be transferred to the MDL. The New Jersey and Puerto Rico 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.

Fact discovery has concluded with respect to an initial set of fewer than 20 sites each that will be the subject of the first trial phase in the New Jersey case and the initial Puerto Rico case. Insufficient information has been developed about the plaintiffs' legal theories or the facts with respect to statewide natural resource damage claims to provide an analysis of the ultimate potential liability of Sunoco in these matters; however, it is reasonably possible that a loss may be realized. Management believes that an adverse determination with respect to one or more of the MTBE cases could have a significant impact on results of operations during the period in which any said adverse determination occurs, but does not believe that any such adverse determination would have a material adverse effect on the Partnership's consolidated financial position.

Other Litigation and Contingencies

In November 2011, a derivative lawsuit was filed in the Judicial District Court of Harris County, Texas naming as defendants ETP, ETP GP, ETP LLC, the boards of directors of ETP LLC (collectively with ETP GP and ETP LLC, the "ETP Defendants"), certain members of management for ETP and ETE, ETE, and Southern Union. The lawsuit is styled W. J. Garrett Trust v. Bill W. Byrne, et al., Cause No. 2011-71702, in the 157th Judicial District Court of Harris County, Texas. Plaintiffs assert claims for breaches of fiduciary duty, breaches of contractual duties, and acts of bad faith against each of the ETP Defendants and the individual defendants. Plaintiffs also assert claims for aiding and abetting and tortious interference with contract against Southern Union. On October 5, 2012, certain defendants filed a motion for summary judgment with respect to the primary allegations in this action. On December 13, 2012, Plaintiffs filed their opposition to the motion for summary judgment. Defendants filed a reply on December 19, 2012. On December 20, 2012, the court conducted an oral hearing on the motion. Plaintiffs filed a post-hearing sur-reply on January 7, 2013. On January 16, 2013, the Court granted defendants' motion for summary judgment. The parties agreed to settle the matter and executed a memorandum of understanding. On October 4, 2013, the Court approved the settlement and ordered the case dismissed with prejudice.

We or our subsidiaries are a party to various legal proceedings and/or regulatory proceedings incidental to our businesses. For each of these matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies, the likelihood of an unfavorable outcome and the availability of insurance coverage. If we determine that an unfavorable outcome of a particular matter is probable and can be estimated, we accrue the contingent obligation, as well as any expected insurance recoverable amounts related to the contingency. As of December 31, 2013 and 2012, accruals of approximately $46 million and $42 million, respectively, were reflected on our consolidated balance sheets related to these contingent obligations. As new information becomes available, our estimates may change. The impact of these changes may have a significant effect on our results of operations in a single period.

The outcome of these matters cannot be predicted with certainty and there can be no assurance that the outcome of a particular matter will not result in the payment of amounts that have not been accrued for the matter. Furthermore, we may revise accrual amounts prior to resolution of a particular contingency based on changes in facts and circumstances or changes in the expected outcome.

No amounts have been recorded in our December 31, 2013 or 2012 consolidated balance sheets for contingencies and current litigation, other than amounts disclosed herein.

Litigation Related to Incident at JJ's Restaurant. On February 19, 2013, there was a natural gas explosion at JJ's Restaurant located at 910 W. 48th Street in Kansas City, Missouri. Effective September 1, 2013, Laclede Gas Company, a subsidiary of The Laclede Group, Inc. ("Laclede"), assumed any and all liability arising from this incident in ETP's sale of the assets of MGE to Laclede.

Attorney General of the Commonwealth of Massachusetts v New England Gas Company. On July 7, 2011, the Massachusetts Attorney General ("AG") filed a regulatory complaint with the MDPU against New England Gas Company with respect to certain environmental cost recoveries. The AG is seeking a refund to New England Gas Company customers for alleged "excessive and imprudently incurred costs" related to legal fees associated with Southern Union's environmental response activities. In the complaint, the AG requests that the MDPU initiate an investigation into the New England Gas Company's collection and reconciliation of recoverable environmental costs including: (i) the prudence of any and all legal fees, totaling approximately $19 million, that were charged by the Kasowitz, Benson, Torres & Friedman firm and passed through the recovery mechanism since 2005, the year when a partner in the firm, the Southern Union former Vice Chairman, President and Chief Operating Officer, joined Southern Union's management team; (ii) the prudence of any and all legal fees that were charged by the Bishop, London & Dodds firm and passed through the recovery mechanism since 2005, the period during which a member of the firm served as Southern Union's Chief Ethics Officer; and (iii) the propriety and allocation of certain legal fees charged that were passed through the recovery mechanism that the AG contends only qualify for a lesser, 50%, level of recovery. Southern Union has filed its answer denying the allegations and moved to dismiss the complaint, in part on a theory of collateral estoppel. The hearing officer has deferred consideration of Southern Union's motion to dismiss. The AG's motion to be reimbursed expert and consultant costs by Southern Union of up to $150,000 was granted. By tariff, these costs are recoverable through rates charged to New England Gas Company customers. The hearing officer previously stayed discovery pending resolution of a dispute concerning the applicability of attorney-client privilege to legal billing invoices. The MDPU issued an interlocutory order on June 24, 2013 that lifted the stay, and discovery has resumed. Southern Union believes it has complied with all applicable requirements regarding its filings for cost recovery and has not recorded any accrued liability; however, Southern Union will continue to assess its potential exposure for such cost recoveries as the matter progresses.

Environmental Matters

Our operations are subject to extensive federal, state and local environmental and safety laws and regulations that require expenditures to ensure compliance, including related to air emissions and wastewater discharges, at operating facilities and for remediation at current and former facilities as well as waste disposal sites. Although we believe our operations are in substantial compliance with applicable environmental laws and regulations, risks of additional costs and liabilities are inherent in the business of transporting, storing, gathering, treating, compressing, blending and processing natural gas, natural gas liquids and other products. As a result, there can be no assurance that significant costs and liabilities will not be incurred. Costs of planning, designing, constructing and operating pipelines, plants and other facilities must incorporate compliance with environmental laws and regulations and safety standards. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, the issuance of injunctions and the filing of federally authorized citizen suits. Contingent losses related to all significant known environmental matters have been accrued and/or separately disclosed. However, we may revise accrual amounts prior to resolution of a particular contingency based on changes in facts and circumstances or changes in the expected outcome.

Environmental exposures and liabilities are difficult to assess and estimate due to unknown factors such as the magnitude of possible contamination, the timing and extent of remediation, the determination of our liability in proportion to other parties, improvements in cleanup technologies and the extent to which environmental laws and regulations may change in the future.

Although environmental costs may have a significant impact on the results of operations for any single period, we believe that such costs will not have a material adverse effect on our financial position.

Based on information available at this time and reviews undertaken to identify potential exposure, we believe the amount reserved for environmental matters is adequate to cover the potential exposure for cleanup costs.

Environmental Remediation

Our subsidiaries are responsible for environmental remediation at certain sites, including the following:

- Certain of our interstate pipelines conduct soil and groundwater remediation related to contamination from past uses of PCBs. PCB assessments are ongoing and, in some cases, our subsidiaries could potentially be held responsible for contamination caused by other parties.
- Certain gathering and processing systems are responsible for soil and groundwater remediation related to releases of hydrocarbons.
- Southern Union’s distribution operations are responsible for soil and groundwater remediation at certain sites related to manufactured gas plants (“MGPs”) and may also be responsible for the removal of old MGP structures.
- Currently operating Sunoco retail sites.
- Legacy sites related to Sunoco, 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.
- Sunoco is potentially subject to joint and several liability for the costs of remediation at sites at which it has been identified as a potentially responsible party (“PRP”). As of December 31, 2013, Sunoco had been named as a PRP at 40 identified or potentially identifiable as “Superfund” sites under federal and/or comparable state law. Sunoco is usually one of a number of companies identified as a PRP at a site. Sunoco has reviewed the nature and extent of its involvement at each site and other relevant circumstances and, based upon Sunoco’s purported nexus to the sites, believes that its potential liability associated with such sites will not be significant.

To the extent estimable, expected remediation costs are included in the amounts recorded for environmental matters in our consolidated balance sheets. In some circumstances, future costs cannot be reasonably estimated because remediation activities are undertaken as claims are made by customers and former customers. To the extent that an environmental remediation obligation is recorded by a subsidiary that applies regulatory accounting policies, amounts that are expected to be recoverable through tariffs or rates are recorded as regulatory assets on our consolidated balance sheets.

The table below reflects the amounts of accrued liabilities recorded in our consolidated balance sheets related to environmental matters that are considered to be probable and reasonably estimable. Except for matters discussed above, we do not have any material environmental matters assessed as reasonably possible that would require disclosure in our consolidated financial statements.

	December 31,	
	2013	2012
Current	$ 45	$ 46
Non-current	350	165
Total environmental liabilities	$ 395	$ 211

In 2013, we have established a wholly-owned captive insurance company to bear certain risks associated with environmental obligations related to certain sites that are no longer operating. The premiums paid to the captive insurance company include estimates for environmental claims that have been incurred but not reported, based on an actuarially determined fully developed claims expense estimate. In such cases, we accrue losses attributable to unasserted claims based on the discounted estimates that are used to develop the premiums paid to the captive insurance company.

During the years ended December 31, 2013 and 2012, Sunoco had $36 million and $12 million, respectively, of expenditures related to environmental cleanup programs.

The EPA’s Spill Prevention, Control and Countermeasures program regulations were recently modified and impose additional requirements on many of our facilities. We expect to expend resources on tank integrity testing and any associated corrective actions as well as potential upgrades to containment structures to comply with the new rules. Costs associated with tank integrity testing and resulting corrective actions cannot be reasonably estimated at this time, but we believe such costs will not have a material adverse effect on our financial position, results of operations or cash flows.

On August 20, 2010, the EPA published new regulations under the federal Clean Air Act ("CAA") to control emissions of hazardous air pollutants from existing stationary reciprocal internal combustion engines. The rule will require us to undertake certain expenditures and activities, likely including purchasing and installing emissions control equipment. In response to an industry group legal challenge to portions of the rule in the U.S. Court of Appeals for the D.C. Circuit and a Petition for Administrative Reconsideration to the EPA, on March 9, 2011, the EPA issued a new proposed rule and direct final rule effective on May 9, 2011 to clarify compliance requirements related to operation and maintenance procedures for continuous parametric monitoring systems. If no further changes to the standard are made as a result of comments to the proposed rule, we would not expect that the cost to comply with the rule's requirements will have a material adverse effect on our financial condition or results of operations. Compliance with the final rule was required by October 2013, and the Partnership believes it is in compliance.

On June 29, 2011, the EPA finalized a rule under the CAA that revised the new source performance standards for manufacturers, owners and operators of new, modified and reconstructed stationary internal combustion engines. The rule became effective on August 29, 2011. The rule modifications may require us to undertake significant expenditures, including expenditures for purchasing, installing, monitoring and maintaining emissions control equipment, if we replace equipment or expand existing facilities in the future. At this point, we are not able to predict the cost to comply with the rule's requirements, because the rule applies only to changes we might make in the future.

Our pipeline operations are subject to regulation by the DOT under the PHMSA, pursuant to which the PHMSA has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. Moreover, the PHMSA, through the Office of Pipeline Safety, has promulgated a rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the rule refers to as "high consequence areas." Activities under these integrity management programs involve the performance of internal pipeline inspections, pressure testing or other effective means to assess the integrity of these regulated pipeline segments, and the regulations require prompt action to address integrity issues raised by the assessment and analysis. 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 future capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines; however, no estimate can be made at this time of the likely range of such expenditures.

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

10. PRICE RISK MANAGEMENT ASSETS AND LIABILITIES:

Commodity Price Risk

We are exposed to market risks related to the volatility of commodity prices. To manage the impact of volatility from these prices, we utilize various exchange-traded and OTC commodity financial instrument contracts. These contracts consist primarily of futures, swaps and options and are recorded at fair value in our consolidated balance sheets.

We inject and hold natural gas in our Bammel storage facility to take advantage of contango markets (i.e., 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 into 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 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. 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 price 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 through either mark-to-market adjustments or the physical withdraw of natural gas.

We are also exposed to market risk on natural gas we retain for fees in our intrastate transportation and storage operations and operational gas sales on our interstate transportation and storage operations. We use financial derivatives to hedge the sales price of this gas, including futures, swaps and options. Certain contracts that qualify for hedge accounting are designated as cash flow hedges of the forecasted sale of natural gas. The change in value, to the extent the contracts are effective, remains in AOCI 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.

We are also exposed to commodity price risk on NGLs and residue gas we retain for fees in our midstream operations whereby our subsidiaries generally 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 for the residue gas and NGLs. We use NGL and crude derivative swap contracts to hedge forecasted sales of NGL and condensate equity volumes. Certain contracts that qualify for hedge accounting are accounted for as cash flow hedges. The change in value, to the extent the contracts are effective, remains in AOCI 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.

We may use derivatives in our NGL transportation and services operations to manage our storage facilities and the purchase and sale of purity NGLs.

Sunoco Logistics utilizes derivatives such as swaps, futures and other derivative instruments to mitigate the risk associated with market movements in the price of refined products and NGLs. These derivative contracts act as a hedging mechanism against the volatility of prices by allowing Sunoco Logistics to transfer this price risk to counterparties who are able and willing to bear it. Since the first quarter 2013, Sunoco Logistics has not designated any of its derivative contracts as hedges for accounting purposes. Therefore, all realized and unrealized gains and losses from these derivative contracts are recognized in the consolidated statements of operations during the current period.

Our trading activities include the use of financial commodity derivatives to take advantage of market opportunities. These trading activities are a complement to our transportation and storage operations and are netted in cost of products sold in our consolidated statements of operations. Additionally, we also have trading activities related to power and natural gas in our all other operations which are also netted in cost of products sold. As a result of our trading activities and the use of derivative financial instruments in our transportation and storage operations, the degree of earnings volatility that can occur may be significant, favorably or unfavorably, from period to period. We attempt to manage this volatility through the use of daily position and profit and loss reports provided to our risk oversight committee, which includes members of senior management, and the limits and authorizations set forth in our commodity risk management policy.

Derivatives are utilized in our all other operations in order to mitigate price volatility and manage fixed price exposure incurred from contractual obligations. We attempt to maintain balanced positions in our marketing activities to protect against volatility in the energy commodities markets; however, net unbalanced positions can exist.

The following table details our outstanding commodity-related derivatives:

	December 31, 2013		December 31, 2012	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark-to-Market Derivatives				
(Trading)				
Natural Gas (MMBtu):				
Fixed Swaps/Futures	9,457,500	2014-2019	—	—
Basis Swaps IFERC/NYMEX[1]	(487,500)	2014-2017	(30,980,000)	2013-2014
Swing Swaps	1,937,500	2014-2016	—	—
Power (Megawatt):				
Forwards	351,050	2014	19,650	2013
Futures	(772,476)	2014	(1,509,300)	2013
Options – Puts	(52,800)	2014	—	—
Options – Calls	103,200	2014	1,656,400	2013
Crude (Bbls) – Futures	103,000	2014	—	—
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	570,000	2014	150,000	2013
Swing Swaps IFERC	(9,690,000)	2014-2016	(83,292,500)	2013
Fixed Swaps/Futures	(8,195,000)	2014-2015	27,077,500	2013
Forward Physical Contracts	5,668,559	2014-2015	11,689,855	2013-2014
Natural Gas Liquid (Bbls) – Forwards/Swaps	(280,000)	2014	(30,000)	2013
Refined Products (Bbls) – Futures	(1,133,600)	2014	(666,000)	2013
Fair Value Hedging Derivatives				
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	(7,352,500)	2014	(18,655,000)	2013
Fixed Swaps/Futures	(50,530,000)	2014	(44,272,500)	2013
Hedged Item – Inventory	50,530,000	2014	44,272,500	2013
Cash Flow Hedging Derivatives				
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	(1,825,000)	2014	—	—
Fixed Swaps/Futures	(12,775,000)	2014	(8,212,500)	2013
Natural Gas Liquid (Bbls) – Forwards/Swaps	(780,000)	2014	(930,000)	2013
Refined Products (Bbls) – Futures	—	—	(98,000)	2013
Crude (Bbls) – Futures	(30,000)	2014	—	—

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

We expect gains of $4 million related to commodity derivatives to be reclassified into earnings over the next 12 months related to amounts currently reported in AOCI. The amount ultimately realized, however, will differ as commodity prices change and the underlying physical transaction occurs.

Interest Rate Risk

We are exposed to market risk for changes in interest rates. To maintain a cost effective capital structure, we borrow funds using a mix of fixed rate debt and variable rate debt. We also manage our interest rate exposure by utilizing interest rate swaps to achieve a desired mix of fixed and variable rate debt. We also utilize forward starting interest rate swaps to lock in the rate on a portion of our anticipated debt issuances.

The following table summarizes our interest rate swaps outstanding, none of which were designated as hedges for accounting purposes:

			Notional Amount Outstanding	
Entity	Term	Type[1]	December 31, 2013	December 31, 2012
ETP	July 2013[2]	Forward-starting to pay a fixed rate of 4.03% and receive a floating rate	$ —	$ 400
ETP	July 2014[2]	Forward-starting to pay a fixed rate of 4.25% and receive a floating rate	400	400
ETP	July 2018	Pay a floating rate plus a spread of 4.17% and receive a fixed rate of 6.70%	600	600
ETP	June 2021	Pay a floating rate plus a spread of 2.17% and receive a fixed rate of 4.65%	400	—
ETP	February 2023	Pay a floating rate plus a spread of 1.32% and receive a fixed rate of 3.60%	400	—
Southern Union [3]	November 2016	Pay a fixed rate of 2.97% and receive a floating rate	—	75
Southern Union [3]	November 2021	Pay a fixed rate of 3.801% and receive a floating rate	275	450

(1) 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. During the year ended December 31, 2013, we settled $400 million of ETP's forward-starting interest rate swaps that had an effective date of July 2013.

(3) In connection with the Panhandle Merger, Southern Union's interest rate swaps outstanding were assumed by Panhandle.

Credit Risk

Credit risk refers to the risk that a counterparty may default on its contractual obligations resulting in a loss to the Partnership. Credit policies have been approved and implemented to govern the Partnership's portfolio of counterparties with the objective of mitigating credit losses. These policies establish guidelines, controls and limits to manage credit risk within approved tolerances by mandating an appropriate evaluation of the financial condition of existing and potential counterparties, monitoring agency credit ratings, and by implementing credit practices that limit exposure according to the risk profiles of the counterparties. Furthermore, the Partnership may at times require collateral under certain circumstances to mitigate credit risk as necessary. We also implement the use of industry standard commercial agreements which allow for the netting of positive and negative exposures associated with transactions executed under a single commercial agreement. Additionally, we utilize master netting agreements to offset credit exposure across multiple commercial agreements with a single counterparty or affiliated group of counterparties.

The Partnership's counterparties consist of a diverse portfolio of customers across the energy industry, including petrochemical companies, commercial and industrials, oil and gas producers, municipalities, utilities and midstream companies. Our overall exposure may be affected positively or negatively by macroeconomic or regulatory changes that could impact our counterparties to one extent or another. Currently, management does not anticipate a material adverse effect in our financial position or results of operations as a consequence of counterparty non-performance.

We have maintenance margin deposits with certain counterparties in the OTC market, primarily independent system operators, and with clearing brokers. Payments on margin deposits are required when the value of a derivative exceeds our pre-established credit limit with the counterparty. Margin deposits are returned to us on or about the settlement date for non-exchange traded derivatives, and we exchange margin calls on a daily basis for exchange traded transactions. Since the margin calls are made daily with the exchange brokers, the fair value of the financial derivative instruments are deemed current and netted in deposits paid to vendors within other current assets in the consolidated balance sheets.

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 sheets and recognized in net income or other comprehensive income.

Derivative Summary

The following table provides a summary of our derivative assets and liabilities:

	Fair Value of Derivative Instruments			
	Asset Derivatives		Liability Derivatives	
	December 31, 2013	December 31, 2012	December 31, 2013	December 31, 2012
Derivatives designated as hedging instruments:				
Commodity derivatives (margin deposits)	$ 3	$ 8	$ (18)	$ (10)
	3	8	(18)	(10)
Derivatives not designated as hedging instruments:				
Commodity derivatives (margin deposits)	227	110	(209)	(116)
Commodity derivatives	39	33	(38)	(34)
Current assets held for sale	—	1	—	—
Non-current assets held for sale	—	1	—	—
Current liabilities held for sale	—	—	—	(9)
Interest rate derivatives	47	55	(95)	(223)
	313	200	(342)	(382)
Total derivatives	$ 316	$ 208	$ (360)	$ (392)

In addition to the above derivatives, $7 million in option premiums were included in price risk management liabilities as of December 31, 2012.

The following table presents the fair value of our recognized derivative assets and liabilities on a gross basis and amounts offset on the consolidated balance sheets that are subject to enforceable master netting arrangements or similar arrangements:

		Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	December 31, 2013	December 31, 2012	December 31, 2013	December 31, 2012
Derivatives in offsetting agreements:					
OTC contracts	Price risk management assets (liabilities)	$ 41	$ 28	$ (38)	$ (27)
Broker cleared derivative contracts	Other current assets (liabilities)	265	150	(318)	(228)
		306	178	(356)	(255)
Offsetting agreements:					
Collateral paid to OTC counterparties	Other current assets	—	—	—	2
Counterparty netting	Price risk management assets (liabilities)	(36)	(25)	36	25
Payments on margin deposit	Other current assets	(1)	—	55	59
		(37)	(25)	91	86
Net derivatives with offsetting agreements		269	153	(265)	(169)
Derivatives without offsetting agreements		47	55	(95)	(223)
Total derivatives		$ 316	$ 208	$ (360)	$ (392)

We disclose the non-exchange traded financial derivative instruments as price risk management assets and liabilities on our consolidated balance sheets at fair value with amounts classified as either current or long-term depending on the anticipated settlement date.

The following tables summarize the amounts recognized with respect to our derivative financial instruments:

	Change in Value Recognized in OCI on Derivatives (Effective Portion)		
	Years Ended December 31,		
	2013	2012	2011
Derivatives in cash flow hedging relationships:			
Commodity derivatives	$ (1)	$ 8	$ 19
Total	$ (1)	$ 8	$ 19

	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)		
		Years Ended December 31,		
		2013	2012	2011
Derivatives in cash flow hedging relationships:				
Commodity derivatives	Cost of products sold	$ 4	$ 14	$ 38
Total		$ 4	$ 14	$ 38

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income Representing Hedge Ineffectiveness and Amount Excluded from the Assessment of Effectiveness		
		Years Ended December 31,		
		2013	2012	2011
Derivatives in fair value hedging relationships (including hedged item):				
Commodity derivatives	Cost of products sold	$ 8	$ 54	$ 34
Total		$ 8	$ 54	$ 34

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income on Derivatives		
		Years Ended December 31,		
		2013	2012	2011
Derivatives not designated as hedging instruments:				
Commodity derivatives – Trading	Cost of products sold	$ (11)	$ (7)	$ (30)
Commodity derivatives – Non-trading	Cost of products sold	(12)	(15)	9
Commodity contracts – Non-trading	Deferred gas purchases	(3)	(26)	—
Interest rate derivatives	Gains (losses) on interest rate derivatives	44	(4)	(77)
Total		$ 18	$ (52)	$ (98)

11. RETIREMENT BENEFITS:

Savings and Profit Sharing Plans

We and our subsidiaries sponsor defined contribution savings and profit sharing plans, which collectively cover virtually all employees. Employer matching contributions are calculated using a formula based on employee contributions. We and our subsidiaries made matching contributions of $38 million, $21 million and $11 million to these 401(k) savings plans for the years ended December 31, 2013, 2012 and 2011, respectively.

Pension and Other Postretirement Benefit Plans

Southern Union

Southern Union has funded non-contributory defined benefit pension plans that cover substantially all employees of Southern Union's distribution operations. Normal retirement age is 65, but certain plan provisions allow for earlier retirement. Pension benefits are calculated under formulas principally based on average earnings and length of service for salaried and non-union employees and average earnings and length of service or negotiated non-wage based formulas for union employees.

The 2012 postretirement benefits expense for Southern Union reflects the impact of curtailment accounting as postretirement benefits for all active participants who did not meet certain criteria were eliminated. Southern Union previously had postretirement health care and life insurance plans that covered substantially of its distribution and transportation and storage operations employees as well as all corporate employees. The health care plans generally provide for cost sharing between Southern Union and its retirees in the form of retiree contributions, deductibles, coinsurance, and a fixed cost cap on the amount Southern Union pays annually to provide future retiree health care coverage under certain of these plans.

Sunoco

Sunoco has both funded and unfunded noncontributory defined benefit pension plans. Sunoco also has plans which provide health care benefits for substantially all of its current retirees ("postretirement benefit plans"). The postretirement benefit plans are unfunded and the costs are shared by Sunoco and its retirees. Prior to the Sunoco Merger on October 5, 2012, pension benefits under Sunoco's defined benefit plans were frozen for most of the participants in these plans at which time Sunoco instituted a discretionary profit-sharing contribution on behalf of these employees in its defined contribution plan. Postretirement medical benefits were also phased down or eliminated for all employees retiring after July 1, 2010. Sunoco has established a trust for its postretirement benefit liabilities by making a tax-deductible contribution of approximately $200 million and restructuring the retiree medical plan to eliminate Sunoco's liability beyond this funded amount. The retiree medical plan change eliminated substantially all of Sunoco's future exposure to variances between actual results and assumptions used to estimate retiree medical plan obligations.

Obligations and Funded Status

Pension and other postretirement benefit liabilities are accrued on an actuarial basis during the years an employee provides services. The following table contains information at the dates indicated about the obligations and funded status of pension and other postretirement plans on a combined basis:

	December 31, 2013			December 31, 2012	
	Pension Benefits				
	Funded Plans	Unfunded Plans	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Change in benefit obligation:					
Benefit obligation at beginning of period	$ 1,117	$ 78	$ 296	$ 1,257	$ 359
Service cost	3	—	—	3	1
Interest cost	33	2	6	15	3
Amendments	—	—	2	—	17
Benefits paid, net	(99)	(16)	(26)	(71)	(8)
Curtailments	—	—	—	—	(80)
Actuarial (gain) loss and other	(74)	(3)	(14)	(9)	4
Settlements	(95)	—	—	—	—
Dispositions	(253)	—	(41)	—	—
Benefit obligation at end of period	632	61	223	1,195	296
Change in plan assets:					
Fair value of plan assets at beginning of period	906	—	312	941	306
Return on plan assets and other	43	—	17	22	5
Employer contributions	—	—	8	14	9
Benefits paid, net	(99)	—	(26)	(71)	(8)
Settlements	(95)	—	—	—	—
Dispositions	(155)	—	(27)	—	—
Fair value of plan assets at end of period	600	—	284	906	312
Amount underfunded (overfunded) at end of period	$ 32	$ 61	$ (61)	$ 289	$ (16)
Amounts recognized in the consolidated balance sheets consist of:					
Non-current assets	$ —	$ —	$ 86	$ —	$ 59
Current liabilities	—	(9)	(2)	(15)	(2)
Non-current liabilities	(32)	(52)	(23)	(274)	(41)
	$ (32)	$ (61)	$ 61	$ (289)	$ 16
Amounts recognized in accumulated other comprehensive loss (pre-tax basis) consist of:					
Net actuarial gain	$ (86)	$ (4)	$ (25)	$ (1)	$ (1)
Prior service cost	—	—	18	—	16
	$ (86)	$ (4)	$ (7)	$ (1)	$ 15

The following table summarizes information at the dates indicated for plans with an accumulated benefit obligation in excess of plan assets:

	December 31, 2013			December 31, 2012	
	Pension Benefits				
	Funded Plans	Unfunded Plans	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Projected benefit obligation	$ 632	$ 61	N/A	$ 1,195	N/A
Accumulated benefit obligation	632	61	223	1,179	$ 225
Fair value of plan assets	600	—	284	906	185

Components of Net Periodic Benefit Cost

	December 31, 2013		December 31, 2012	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Net Periodic Benefit Cost:				
Service cost	$ 3	$ —	$ 3	$ 1
Interest cost	35	6	15	3
Expected return on plan assets	(54)	(9)	(21)	(5)
Prior service cost amortization	—	1	—	—
Actuarial loss amortization	2	—	—	—
Special termination benefits charge	—	—	2	—
Curtailment recognition[(1)]	—	—	—	(15)
Settlements	(2)	—	—	—
	(16)	(2)	(1)	(16)
Regulatory adjustment[(2)]	5	—	9	2
Net periodic benefit cost	$ (11)	$ (2)	$ 8	$ (14)

(1) Subsequent to the Southern Union Merger, Southern Union amended certain of its other postretirement employee benefit plans, which prospectively restrict participation in the plans for the impacted active employees. The plan amendments resulted in the plans becoming currently over-funded and, accordingly, Southern Union recorded a pre-tax curtailment gain of $75 million. Such gain was offset by establishment of a non-current refund liability in the amount of $60 million. As such, the net curtailment gain recognition was $15 million.

(2) Southern Union has historically recovered certain qualified pension benefit plan and other postretirement benefit plan costs through rates charged to utility customers in its distribution operations. Certain utility commissions require that the recovery of these costs be based on the Employee Retirement Income Security Act of 1974, as amended, or other utility commission specific guidelines. The difference between these regulatory-based amounts and the periodic benefit cost calculated pursuant to GAAP is deferred as a regulatory asset or liability and amortized to expense over periods in which this difference will be recovered in rates, as promulgated by the applicable utility commission.

Assumptions

The weighted-average assumptions used in determining benefit obligations at the dates indicated are shown in the table below:

	December 31, 2013		December 31, 2012	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Discount rate	4.65%	2.33%	3.41%	2.39%
Rate of compensation increase	N/A	N/A	3.17%	N/A

The weighted-average assumptions used in determining net periodic benefit cost for the periods presented are shown in the table below:

	December 31, 2013		December 31, 2012	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Discount rate	3.50%	2.68%	2.37%	2.43%
Expected return on assets:				
Tax exempt accounts	7.50%	6.95%	7.63%	7.00%
Taxable accounts	N/A	4.42%	N/A	4.50%
Rate of compensation increase	N/A	N/A	3.02%	N/A

The long-term expected rate of return on plan assets was estimated based on a variety of factors including the historical investment return achieved over a long-term period, the targeted allocation of plan assets and expectations concerning future returns in the marketplace for both equity and fixed income securities. Current market factors such as inflation and interest rates are evaluated before long-term market assumptions are determined. Peer data and historical returns are reviewed to ensure reasonableness and appropriateness.

The assumed health care cost trend rates used to measure the expected cost of benefits covered by Southern Union and Sunoco's other postretirement benefit plans are shown in the table below:

	December 31,	
	2013	2012
Health care cost trend rate assumed for next year	7.57%	7.78%
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	5.42%	5.32%
Year that the rate reaches the ultimate trend rate	2018	2018

Changes in the health care cost trend rate assumptions are not expected to have a significant impact on postretirement benefits.

Plan Assets

For the Southern Union plans, the overall investment strategy is to maintain an appropriate balance of actively managed investments with the objective of optimizing longer-term returns while maintaining a high standard of portfolio quality and achieving proper diversification. To achieve diversity within its pension plan asset portfolio, Southern Union has targeted the following asset allocations: equity of 25% to 70%, fixed income of 15% to 35%, alternative assets of 10% to 35% and cash of 0% to 10%. To achieve diversity within its other postretirement plan asset portfolio, Southern Union has targeted the following asset allocations: equity of 25% to 35%, fixed income of 65% to 75% and cash and cash equivalents of 0% to 10%.

The investment strategy of Sunoco funded defined benefit plans is to achieve consistent positive returns, after adjusting for inflation, and to maximize long-term total return within prudent levels of risk through a combination of income and capital appreciation. The objective of this strategy is to reduce the volatility of investment returns, maintain a sufficient funded status of the plans and limit required contributions. Sunoco has targeted the following asset allocations: equity of 35%, fixed income of 55%, and private equity investments of 10%. Sunoco anticipates future shifts in targeted asset allocation from equity securities to fixed income securities if funding levels improve due to asset performance or Sunoco contributions.

The fair value of the pension plan assets by asset category at the dates indicated is as follows:

	Fair Value as of December 31, 2013	Fair Value Measurements at December 31, 2013 Using Fair Value Hierarchy		
		Level 1	Level 2	Level 3
Asset Category:				
Cash and cash equivalents	$ 12	$ 12	$ —	$ —
Mutual funds[1]	368	—	281	87
Fixed income securities	220	—	220	—
Total	$ 600	$ 12	$ 501	$ 87

(1) Primarily comprised of approximately 66% equities, 10% fixed income securities, and 24% in other investments as of December 31, 2013.

	Fair Value as of December 31, 2012	Fair Value Measurements at December 31, 2012 Using Fair Value Hierarchy		
		Level 1	Level 2	Level 3
Asset Category:				
Cash and cash equivalents	$ 25	$ 25	$ —	$ —
Mutual funds[1]	516	—	433	83
Fixed income securities	354	—	354	—
Multi-strategy hedge funds[2]	11	—	11	—
Total	$ 906	$ 25	$ 798	$ 83

(1) Primarily comprised of approximately 36% equities, 54% fixed income securities, and 10% in other investments as of December 31, 2012.

(2) Primarily includes hedge funds that invest in multiple strategies, including relative value, opportunistic/macro, long/short equities, merger arbitrage/event driven, credit, and short selling strategies, to generate long-term capital appreciation through a portfolio having a diversified risk profile with relatively low volatility and a low correlation with traditional equity and fixed-income markets. These investments can generally be redeemed effective as of the last day of a calendar quarter at the net asset value per share of the investment with approximately 65 days prior written notice.

The fair value of other postretirement plan assets by asset category at the dates indicated is as follows:

	Fair Value as of December 31, 2013	Fair Value Measurements at December 31, 2013 Using Fair Value Hierarchy		
		Level 1	Level 2	Level 3
Asset Category:				
Cash and Cash Equivalents	$ 10	$ 10	$ —	$ —
Mutual funds[1]	130	112	18	—
Fixed income securities	144	—	144	—
Total	$ 284	$ 122	$ 162	$ —

(1) Primarily comprised of approximately 41% equities, 48% fixed income securities, 6% cash, and 5% in other investments as of December 31, 2013.

	Fair Value as of December 31, 2012	Fair Value Measurements at December 31, 2012 Using Fair Value Hierarchy		
		Level 1	Level 2	Level 3
Asset Category:				
Cash and Cash Equivalents	$ 7	$ 7	$ —	$ —
Mutual funds[(1)]	147	126	21	—
Fixed income securities	158	—	158	—
Total	$ 312	$ 133	$ 179	$ —

(1) Primarily comprised of approximately 19% equities, 74% fixed income securities, 4% cash, and 3% in other investments as of December 31, 2012.

The Level 1 plan assets are valued based on active market quotes. The Level 2 plan assets are valued based on the net asset value per share (or its equivalent) of the investments, which was not determinable through publicly published sources but was calculated consistent with authoritative accounting guidelines. See Note 2 for information related to the framework used to measure the fair value of its pension and other postretirement plan assets.

Contributions

We expect to contribute approximately $23 million to pension plans and approximately $18 million to other postretirement plans in 2014. The costs of the plans are funded in accordance with federal regulations, not to exceed the amounts deductible for income tax purposes.

Benefit Payments

Southern Union and Sunoco’s estimate of expected benefit payments, which reflect expected future service, as appropriate, in each of the next five years and in the aggregate for the five years thereafter are shown in the table below:

	Pension Benefits		
Years	Funded Plans	Unfunded Plans	Other Postretirement Benefits (Gross, Before Medicare Part D)
2014	$ 82	$ 9	$ 31
2015	77	9	29
2016	67	8	28
2017	61	7	26
2018	56	7	24
2019 – 2023	220	23	87

The Medicare Prescription Drug Act provides for a prescription drug benefit under Medicare (“Medicare Part D”) as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a prescription drug benefit that is at least actuarially equivalent to Medicare Part D.

Southern Union does not expect to receive any Medicare Part D subsidies in any future periods.

12. RELATED PARTY TRANSACTIONS:

ETE has agreements with subsidiaries to provide or receive various general and administrative services. ETE pays us to provide services on its behalf and on behalf of other subsidiaries of ETE, which includes the reimbursement of various general and administrative services for expenses incurred by us on behalf of Regency.

In the ordinary course of business, we provide Regency with certain natural gas and NGLs sales and transportation services and compression equipment, and Regency provides us with certain contract compression services. These related party transactions are generally based on transactions made at market-related rates.

Sunoco Logistics has an agreement with PES relating to the Fort Mifflin Terminal Complex. Under this agreement, PES will deliver an average of 300,000 Bbls/d of crude oil and refined products per contract year at the Fort Mifflin facility. PES does not have exclusive use of the Fort Mifflin Terminal Complex; however, Sunoco Logistics is obligated to provide the necessary tanks, marine docks and pipelines for PES to meet its minimum requirements under the agreement. Sunoco Logistics entered into a ten-year agreement to provide terminalling services to PES in September 2012.

In September 2012, Sunoco assigned its lease for the use of Sunoco Logistics' inter-refinery pipelines between the Philadelphia and Marcus Hook refineries to PES. Under the 20-year lease agreement which expires in February 2022, PES leases the inter-refinery pipelines for an annual fee which escalates at 1.67% each January 1 for the term of the agreement. The lease agreement also requires PES to reimburse Sunoco Logistics for any non-routine maintenance expenditures, as defined, incurred during the term of the agreement. There were no material reimbursements under this agreement during the periods presented.

In connection with the acquisition of the Marcus Hook Facility in June 2013, Sunoco Logistics assumed an agreement to provide butane storage and terminal services to PES at the facility. The 10 year agreement extends through September 2022.

Sunoco Logistics has agreements with PES whereby PES purchases crude oil, at market-based rates, for delivery to Sunoco Logistics' Fort Mifflin and Eagle Point terminal facilities. These agreements contain minimum volume commitments and extend through 2014.

The renegotiated terms of the agreements with PES provide PES with the option to purchase the Fort Mifflin and Belmont terminals if certain triggering events occur, including a sale of substantially all of the assets or operations of the Philadelphia refinery, an initial public offering or a public debt filing of more than $200 million. The purchase price for each facility would be established based on a fair value amount determined by designated third parties.

The following table summarizes the affiliated revenues on our consolidated statements of operations:

	Years Ended December 31,		
	2013	2012	2011
Affiliated revenues	$ 1,550	$ 173	$ 690

The following table summarizes the related company balances on our consolidated balance sheets:

	December 31,	
	2013	2012
Accounts receivable from related companies:		
ETE	$ 18	$ 16
Regency	53	10
PES	7	60
FGT	29	2
Eastern Gulf	24	—
Other	34	6
Total accounts receivable from related companies:	$ 165	$ 94
Accounts payable to related companies:		
ETE	$ 8	$ 7
Regency	24	2
PES	—	13
FGT	8	—
Other	5	2
Total accounts payable to related companies:	$ 45	$ 24

13. SUPPLEMENTAL FINANCIAL STATEMENT INFORMATION:

Following are the financial statements of ETP GP, which are included to provide additional information with respect to ETP GP's financial position, results of operations and cash flows on a stand-alone basis:

BALANCE SHEETS

	December 31, 2013	December 31, 2012
ASSETS		
INVESTMENT IN ENERGY TRANSFER PARTNERS	$ 171	$ 188
GOODWILL	29	29
Total assets	$ 200	$ 217
LIABILITIES AND EQUITY		
EQUITY:		
General Partner	$ —	$ —
Limited Partners:		
Class A Limited Partner interest	70	86
Class B Limited Partner interest	130	131
Total partners' capital	200	217
Total liabilities and equity	$ 200	$ 217

STATEMENTS OF OPERATIONS

	Years Ended December 31, 2013	2012	2011
OTHER INCOME (EXPENSE):			
Equity in earnings of unconsolidated affiliates	$ 506	$ 461	$ 433
NET INCOME BEFORE INCOME TAX EXPENSE	506	461	433
Income tax expense	—	—	—
NET INCOME	$ 506	$ 461	$ 433

STATEMENTS OF CASH FLOWS

	Years Ended December 31, 2013	2012	2011
NET CASH PROVIDED BY OPERATING ACTIVITIES	$ 523	$ 454	$ 426
CASH FLOWS FROM FINANCING ACTIVITIES:			
Distributions to partners	(523)	(454)	(426)
Net cash used in financing activities	(523)	(454)	(426)
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	—	—	—
CASH AND CASH EQUIVALENTS, beginning of period	—	—	—
CASH AND CASH EQUIVALENTS, end of period	$ —	$ —	$ —

4. REGENCY ENERGY PARTNERS LP FINANCIAL STATEMENTS

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Partners
Regency Energy Partners LP

We have audited the accompanying consolidated balance sheets of Regency Energy Partners LP (a Delaware limited partnership) and subsidiaries (the "Partnership") as of December 31, 2013 and 2012, and the related consolidated statements of operations, comprehensive income, cash flows, and partners' capital and noncontrolling interest for each of the three years in the period ended December 31, 2013. 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 financial statements of Midcontinent Express Pipeline LLC, a 50 percent owned investee company, the Partnership's investment in which is accounted for under the equity method of accounting. The Partnership's investment in Midcontinent Express Pipeline LLC as of December 31, 2013 and 2012 was $548 million and $581 million, respectively, and its equity in the earnings of Midcontinent Express Pipeline LLC was $39 million, $42 million, and $43 million, respectively, for each of the three years in the period ended December 31, 2013. Those statements were audited by other auditors, whose reports have been furnished to us, and our opinion, insofar as it relates to the amounts included for Midcontinent Express Pipeline LLC, is based solely on the reports 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 reports of the other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audits and the reports of the other auditors, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Regency Energy Partners LP and subsidiaries as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1, the accompanying consolidated financial statements have been adjusted to reflect the acquisition of an entity under common control, which has been accounted for in a manner similar to a pooling of interests.

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, 2013, based on criteria established in the 1992 Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 27, 2014 (not separately included herein) expressed an unqualified opinion thereon.

/s/ GRANT THORNTON LLP

Dallas, Texas
February 27, 2014

Regency Energy Partners LP

Consolidated Balance Sheets
(in millions except unit data)

	December 31, 2013	December 31, 2012
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 19	$ 53
Trade accounts receivable	292	222
Related party receivables	28	8
Inventories	42	27
Other current assets	19	30
Total current assets	400	340
Property, Plant and Equipment:		
Gathering and transmission systems	1,671	1,308
Compression equipment	1,627	1,326
Gas plants and buildings	825	568
Other property, plant and equipment	414	377
Construction-in-progress	513	507
Total property, plant and equipment	5,050	4,086
Less accumulated depreciation	(632)	(400)
Property, plant and equipment, net	4,418	3,686
Other Assets:		
Investments in unconsolidated affiliates	2,097	2,214
Other, net of accumulated amortization of debt issuance costs of $24 and $17	57	43
Total other assets	2,154	2,257
Intangible Assets and Goodwill:		
Intangible assets, net of accumulated amortization of $107 and $77	682	712
Goodwill	1,128	1,128
Total intangible assets and goodwill	1,810	1,840
TOTAL ASSETS	$ 8,782	$ 8,123
LIABILITIES & PARTNERS' CAPITAL AND NONCONTROLLING INTEREST		
Current Liabilities:		
Drafts payable	$ 26	$ 10
Trade accounts payable	291	255
Related party payables	69	95
Accrued interest	38	30
Other current liabilities	51	99
Total current liabilities	475	489
Long-term derivative liabilities	19	25
Other long-term liabilities	30	39
Long-term debt, net	3,310	2,157
Commitments and contingencies		
Series A Preferred Units, redemption amount of $38 and $85	32	73
Partners' Capital and Noncontrolling Interest:		
Common units (214,287,955 and 174,574,175 units authorized; 210,850,232 and 170,951,457 units issued and outstanding at December 31, 2013 and 2012)	3,886	3,207
Class F common units (6,274,483 and 0 units authorized, issued and outstanding at December 31, 2013 and 2012)	146	—
General partner interest	782	326
Predecessor equity	—	1,733
Accumulated other comprehensive loss	—	(3)
Total partners' capital	4,814	5,263
Noncontrolling interest	102	77
Total partners' capital and noncontrolling interest	4,916	5,340
TOTAL LIABILITIES AND PARTNERS' CAPITAL AND NONCONTROLLING INTEREST	$ 8,782	$ 8,123

See accompanying notes to consolidated financial statements

Regency Energy Partners LP

Consolidated Statements of Operations
(in millions except unit data and per unit data)

	Years Ended December 31, 2013	2012	2011
REVENUES			
Gas sales, including related party amounts of $71, $42, and $23	$ 826	$ 508	$ 456
NGL sales, including related party amounts of $81, $28, and $365	1,053	991	603
Gathering, transportation and other fees, including related party amounts of $26, $29, and $24	545	401	351
Net realized and unrealized (loss) gain from derivatives	(8)	23	(19)
Other, including related party amounts of $-, $1, and $10	105	77	43
Total revenues	2,521	2,000	1,434
OPERATING COSTS AND EXPENSES			
Cost of sales, including related party amounts of $56, $35, and $22	1,793	1,387	1,013
Operation and maintenance	296	228	147
General and administrative, including related party amounts of $11, $15, and $17	88	100	67
Loss (gain) on asset sales, net	2	3	(2)
Depreciation and amortization	287	252	169
Total operating costs and expenses	2,466	1,970	1,394
OPERATING INCOME	55	30	40
Income from unconsolidated affiliates	135	105	120
Interest expense, net	(164)	(122)	(103)
Loss on debt refinancing, net	(7)	(8)	—
Other income and deductions, net	7	29	17
INCOME BEFORE INCOME TAXES	26	34	74
Income tax benefit	(1)	—	—
NET INCOME	$ 27	$ 34	$ 74
Net income attributable to noncontrolling interest	(8)	(2)	(2)
NET INCOME ATTRIBUTABLE TO REGENCY ENERGY PARTNERS LP	$ 19	$ 32	$ 72
Amounts attributable to Series A preferred units	6	10	8
General partner’s interest, including IDRs	11	9	7
Beneficial conversion feature for Class F units	4	—	—
Pre-acquisition loss from SUGS allocated to predecessor equity	(36)	(14)	—
Limited partners’ interest in net income	$ 34	$ 27	$ 57
Basic and diluted income per common unit:			
Amount allocated to common units	$ 34	$ 27	$ 57
Weighted average number of common units outstanding	196,227,348	167,492,735	145,490,869
Basic income per common unit	$ 0.17	$ 0.16	$ 0.39
Diluted income per common unit	$ 0.17	$ 0.13	$ 0.32
Distributions per common unit	$ 1.87	$ 1.84	$ 1.81
Amount allocated to Class F units due to beneficial conversion feature	$ 4	$ —	$ —
Total number of Class F units outstanding	6,274,483	—	—
Income per Class F unit due to beneficial conversion feature	$ 0.72	$ —	$ —

See accompanying notes to consolidated financial statements

Regency Energy Partners LP

Consolidated Statements of Comprehensive Income
(in millions)

	Years Ended December 31,		
	2013	2012	2011
Net income	$ 27	$ 34	$ 74
Other comprehensive income:			
Net cash flow hedge amounts reclassified to earnings	—	6	19
Change in fair value of cash flow hedges	—	(4)	(13)
Total other comprehensive income	$ —	$ 2	$ 6
Comprehensive income	$ 27	$ 36	$ 80
Comprehensive income attributable to noncontrolling interest	8	2	2
Comprehensive income attributable to Regency Energy Partners LP	$ 19	$ 34	$ 78

See accompanying notes to consolidated financial statements

Regency Energy Partners LP

Consolidated Statements of Partners' Capital and Noncontrolling Interest
(in millions)

	Regency Energy Partners LP						
	Common Units	Class F Common Units	General Partner Interest	Predecessor Equity	AOCI	Noncontrolling Interest	Total
Balance—December 31, 2010	$ 2,941	$ —	$ 333	$ —	$ (11)	$ 31	$ 3,294
Common unit offerings, net of costs	436	—	—	—	—	—	436
Unit-based compensation expenses	3	—	—	—	—	—	3
Partner distributions	(264)	—	(10)	—	—	—	(274)
Net income	65	—	7	—	—	2	74
Distributions to Series A Preferred Units	(8)	—	—	—	—	—	(8)
Net cash flow hedge amounts reclassified to earnings	—	—	—	—	19	—	19
Net change in fair value of cash flow hedges	—	—	—	—	(13)	—	(13)
Balance—December 31, 2011	$ 3,173		$ 330	$ —	$ (5)	$ 33	$ 3,531
Common unit offerings, net of costs	297	—	—	—	—	—	297
Issuance of common units under equity distribution program, net of costs	15	—	—	—	—	—	15
Common units issued under LTIP, net of forfeitures and tax withholding	(1)	—	—	—	—	—	(1)
Unit-based compensation expenses	5	—	—	—	—	—	5
Partner distributions	(309)	—	(13)	—	—	—	(322)
Net income (loss)	37	—	9	(14)	—	2	34
Contributions from noncontrolling interest	—	—	—	—	—	42	42
Distributions to Series A Preferred Units	(8)	—	—	—	—	—	(8)
Accretion of Series A Preferred Units	(2)	—	—	—	—	—	(2)
Net cash flow hedge amounts reclassified to earnings	—	—	—	—	5	—	5
Contribution of net investment to unitholders	—	—	—	1,747	(3)	—	1,744
Balance—December 31, 2012	$ 3,207	$ —	$ 326	$ 1,733	$ (3)	$ 77	$ 5,340
Contribution of net investment to the Partnership	—	—	1,925	(1,928)	3	—	—
Issuance of common units in connection with the SUGS Acquisition, net of costs	819	—	(819)	—	—	—	—
Issuance of Class F common units in connection with the SUGS Acquisition, net of costs	—	142	(142)	—	—	—	—
Contribution of assets between entities under common control below historical cost	—	—	(504)	231	—	—	(273)
Issuance of common units under equity distribution program, net of costs	149	—	—	—	—	—	149
Conversion of Series A Preferred Units for common units	41	—	—	—	—	—	41
Unit-based compensation expenses	7	—	—	—	—	—	7
Partner distributions and distributions on unvested unit awards	(371)	—	(15)	—	—	—	(386)
Contributions from noncontrolling interest	—	—	—	—	—	17	17
Net income (loss)	40	4	11	(36)	—	8	27
Distributions to Series A Preferred Units	(6)	—	—	—	—	—	(6)
Balance—December 31, 2013	$ 3,886	$ 146	$ 782	$ —	$ —	$ 102	$ 4,916

See accompanying notes to consolidated financial statements

Regency Energy Partners LP

Consolidated Statements of Cash Flows
(in millions)

	Years Ended December 31,		
	2013	2012	2011
OPERATING ACTIVITIES			
Net income	$ 27	$ 34	$ 74
Reconciliation of net income to net cash flows provided by operating activities:			
Depreciation and amortization, including debt issuance cost amortization and bond premium write-off and amortization	293	259	175
Income from unconsolidated affiliates	(135)	(105)	(120)
Derivative valuation changes	6	(12)	(21)
Loss (gain) on asset sales, net	2	3	(2)
Unit-based compensation expenses	7	5	3
Cash flow changes in current assets and liabilities:			
Trade accounts receivable and related party receivables	(96)	—	(8)
Other current assets and other current liabilities	(54)	10	11
Trade accounts payable, related party payables and deferred revenues	119	18	23
Distributions of earnings received from unconsolidated affiliates	142	121	119
Cash flow changes in other assets and liabilities	125	(9)	—
Net cash flows provided by operating activities	436	324	254
INVESTING ACTIVITIES			
Capital expenditures	(1,034)	(560)	(406)
Capital contributions to unconsolidated affiliates	(148)	(356)	(53)
Distributions in excess of earnings of unconsolidated affiliates	249	83	74
Acquisition of investment in unconsolidated affiliates, net of cash received	—	—	(594)
Acquisitions, net of cash received	(475)	—	—
Proceeds from asset sales	15	26	24
Net cash flows used in investing activities	(1,393)	(807)	(955)
FINANCING ACTIVITIES			
Borrowings (repayments) under revolving credit facility, net	318	(140)	47
Proceeds from issuance of senior notes	1,000	700	500
Redemptions of senior notes	(163)	(88)	—
Debt issuance costs	(24)	(15)	(10)
Partner distributions and distributions on unvested unit awards	(386)	(322)	(274)
Contributions from noncontrolling interest	17	42	—
Contributions from previous parent	—	51	—
Drafts payable	18	4	2
Common units issued under LTIP, net of forfeitures and tax withholding	—	(1)	—
Common unit offerings, net of issuance costs	—	297	436
Common units issued under equity distribution program, net of costs	149	15	—
Distributions to Series A Preferred Units	(6)	(8)	(8)
Net cash flows provided by financing activities	923	535	693
Net change in cash and cash equivalents	(34)	52	(8)
Cash and cash equivalents at beginning of period	53	1	9
Cash and cash equivalents at end of period	$ 19	$ 53	$ 1

Supplemental cash flow information:			
Accrued capital expenditures	$ 60	$ 136	$ 24
Issuance of Class F and common units in connection with SUGS Acquisition	961	—	—
Interest paid, net of amounts capitalized	146	112	83
Income taxes paid	—	—	2
Accrued capital contribution to unconsolidated affiliate	13	23	—

See accompanying notes to consolidated financial statements

Regency Energy Partners LP
Notes to Consolidated Financial Statements
(Tabular dollar amounts, except unit and per unit data, are in millions)

1. Organization and Basis of Presentation

Organization. The consolidated financial statements presented herein contain the results of Regency Energy Partners LP and its subsidiaries (the "Partnership"), a Delaware limited partnership. The Partnership was formed on September 8, 2005, and completed its IPO on February 3, 2006. The Partnership and its subsidiaries are engaged in the business of gathering and processing, compression, treating and transportation of natural gas and the transportation, fractionation and storage of NGLs. Regency GP LP is the Partnership's general partner and Regency GP LLC is the managing general partner of the Partnership and the general partner of Regency GP LP.

SUGS Acquisition. In April 2013, the Partnership acquired SUGS from Southern Union, a wholly-owned subsidiary of Holdco, for $1.5 billion (the "SUGS Acquisition"). The Partnership financed the acquisition by issuing to Southern Union 31,372,419 of common units and 6,274,483 Class F common units. The Class F common units are not entitled to participate in the Partnership's distributions for twenty-four months post-transaction closing. The remaining $600 million, less $107 million of closing adjustments, was paid in cash. In addition, ETE agreed to forgo IDR payments on the Partnership common units issued with this transaction for the twenty-four months post-transaction closing and to suspend the $10 million annual management fee paid by the Partnership for two years post-transaction close.

The common units and Class F common units related to the SUGS Acquisition were issued in a private placement conducted in accordance with the exemption from registration requirements of the Securities Act of 1933, as amended under Section 4(2) thereof. The Class F common units will convert into common units on a one-for-one basis in May 2015.

The cash portion of the SUGS Acquisition was funded from the net proceeds of $600 million of senior notes issued by the Partnership on April 30, 2013 in a private placement. In December 2013, these senior notes were exchanged for senior notes that are substantially identical, except that the exchange senior notes are registered under federal securities law and do not have any transfer restrictions. In January 2014, Panhandle Eastern Pipe Line Company, LP ("PEPL") entered into an agreement and plan of merger with Southern Union and PEPL Holdings, pursuant to which each of Southern Union and PEPL Holdings were merged with and into PEPL, with PEPL as the surviving entity. In connection with this merger, PEPL assumed the guarantee of collection with respect to the payment of the principal amounts of the senior notes issued.

The Partnership accounted for the SUGS Acquisition in a manner similar to the pooling of interest method of accounting, as it was a transaction between commonly controlled entities. Under this method of accounting, the Partnership reflected historical balance sheet data for the Partnership and SUGS instead of reflecting the fair market value of SUGS assets and liabilities from the date of acquisition forward. The Partnership retrospectively adjusted its financial statements to include the balances and operations of SUGS from March 26, 2012 (the date upon which common control began). The SUGS Acquisition does not impact historical earnings per unit as pre-acquisition earnings were allocated to predecessor equity.

The assets acquired and liabilities assumed in the SUGS Acquisition were as follows:

	April 30, 2013
Current assets	$ 113
Property, plant and equipment, net	1,608
Goodwill	337
Other non-current assets	1
Total assets acquired	$ 2,059
Less:	
Current liabilities	(93)
Non-current liabilities	(36)
Net assets acquired	$ 1,930

The following table presents the revenues and net income for the previously separate entities and combined amounts presented herein:

	Years Ended December 31,	
	2013	2012
Revenues:		
Partnership	$ 2,253	$ 1,339
SUGS (1)	268	661
Combined	$ 2,521	$ 2,000
Net income (loss):		
Partnership	$ 63	$ 48
SUGS (1)	(36)	(14)
Combined	$ 27	$ 34

(1) Combined amounts attributable to SUGS include the period from March 26, 2012 to December 31, 2012 for the year ended December 31, 2012, and the period from January 1, 2013 to April 30, 2013 for the year ended December 31, 2013. Subsequent to the closing of the SUGS Acquisition on April 30, 2013, the results of SUGS were attributable to the Partnership.

Basis of presentation. The consolidated financial statements of the Partnership have been prepared in accordance with GAAP and include the accounts of all controlled subsidiaries after the elimination of all intercompany accounts and transactions. Certain prior year numbers have been conformed to the current year presentation.

2. Summary of Significant Accounting Policies

Use of Estimates. These consolidated financial statements have been prepared in conformity with GAAP, which includes the use of estimates and assumptions by management that affect the reported amounts of assets, liabilities, revenues, expenses and disclosure of contingent assets and liabilities that exist at the date of the financial statements. Although these estimates are based on management’s available knowledge of current and expected future events, actual results could be different from those estimates.

Common Control Transactions. Entities and assets acquired from ETE and its affiliates are accounted for as common control transactions whereby the net assets acquired are combined with the Partnership’s net assets at their historical amounts. If consideration transferred differs from the carrying value of the net assets acquired, the excess or deficiency is treated as a capital transaction similar to a dividend or capital contribution. To the extent that such transactions require prior periods to be recast, historical net equity amounts prior to the transaction date are reflected in predecessor equity.

Cash and Cash Equivalents. Cash and cash equivalents include temporary cash investments with original maturities of three months or less.

Equity Method Investments. The equity method of accounting is used to account for the Partnership’s interest in investments of greater than 20% voting interest or where the Partnership exerts significant influence over an investee but lacks control over the investee.

Inventories. Inventories are valued at the lower of cost or market and include materials and parts primarily utilized by the Contract Services segment.

Property, Plant and Equipment. Property, plant and equipment is recorded at historical cost of construction or, upon acquisition, the fair value of the assets acquired. Gains or losses on sales or retirements of assets are included in operating income unless the disposition is treated as discontinued operations. Natural gas and NGLs used to maintain pipeline minimum pressures is and classified as property, plant and equipment. Financing costs associated with the construction of larger assets requiring ongoing efforts over a period of time are capitalized. For the years ended December 31, 2013, 2012 and 2011, the Partnership capitalized interest of $2 million, $1 million and $1 million, respectively. The costs of maintenance and repairs, which are not significant improvements, are expensed when incurred. Expenditures to extend the useful lives of the assets are capitalized.

Depreciation expense related to property, plant and equipment was $258 million, $219 million, and $138 million for the years ended December 31, 2013, 2012 and 2011, respectively. In March 2012, the Partnership recorded a $7 million “out-of-period” adjustment to depreciation expense to correct the estimated useful lives of certain assets to comply with its policy.

Depreciation of property, plant and equipment is recorded on a straight-line basis over the following estimated useful lives:

Functional Class of Property	**Useful Lives (Years)**
Gathering and Transmission Systems	10 - 50
Compression Equipment	2 - 30
Gas Plants and Buildings	5 - 35
Other property, plant and equipment	3 - 15

Intangible Assets. As of December 31, 2013, intangible assets consisted of trade names and customer relations, and are amortized on a straight line basis over their estimated useful lives, which is the period over which the assets are expected to contribute directly or indirectly to the Partnership’s future cash flows. The estimated useful lives range from 20 to 30 years.

The Partnership assesses long-lived assets, including property, plant and equipment and intangible assets, for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability is assessed by comparing the carrying amount of an asset to undiscounted future net cash flows expected to be generated by the asset. If such assets are considered to be impaired, the impairment to be recognized is measured as the amount by which the carrying amounts exceed the fair value of the assets. The Partnership did not record any impairment in 2013, 2012 or 2011.

Goodwill. Goodwill represents the excess of the purchase price over the fair value of identifiable net assets acquired in a business combination. Goodwill is not amortized, but is tested for impairment annually based on the carrying values as of November 30 or December 31 depending upon the reporting unit, or more frequently if impairment indicators arise that suggest the carrying value of goodwill may not be recovered. The Partnership has the option to first assess qualitative factors to determine whether it is more likely than not that the fair value of the reporting unit is less than its carrying amount as a basis for determining whether further impairment testing is necessary. Impairment is indicated when the carrying amount of a reporting unit exceeds its fair value. To estimate the fair value of the reporting units, the Partnership makes estimates and judgments about future cash flows, as well as revenues, cost of sales, operating expenses, capital expenditures and net working capital based on assumptions that are consistent with the Partnership’s most recent forecast. At the time it is determined that an impairment has occurred, the carrying value of the goodwill is written down to its fair value. The Partnership did not record any impairment in 2013, 2012 or 2011.

Other Assets, net. Other assets, net primarily consists of debt issuance costs, which are capitalized and amortized to interest expense, net over the life of the related debt.

Gas Imbalances. Quantities of natural gas or NGLs over-delivered or under-delivered related to imbalance agreements are recorded monthly as other current assets or other current liabilities using then current market prices or the weighted average prices of natural gas or NGLs at the plant or system pursuant to imbalance agreements for which settlement prices are not contractually established. Within certain volumetric limits determined at the sole discretion of the creditor, these imbalances are generally settled by deliveries of natural gas. Imbalance receivables and payables as of December 31, 2013 and 2012 were immaterial.

Asset Retirement Obligations. Legal obligations associated with the retirement of long-lived assets are recorded at fair value at the time the obligations are incurred, if a reasonable estimate of fair value can be made. Present value techniques are used which reflect assumptions such as removal and remediation costs, inflation, and profit margins that third parties would demand to settle the amount of the future obligation. The Partnership does not include a market risk premium for unforeseeable circumstances in its fair value estimates because such a premium cannot be reliably estimated. Upon initial recognition of the liability, costs are capitalized as a part of the long-lived asset and allocated to expense over the useful life of the related asset. The liability is accreted to its present value each period with accretion being recorded to operating expense with a corresponding increase in the carrying amount of the liability. The ARO assets and liabilities were immaterial as of December 31, 2013.

Environmental. The Partnership's operations are subject to federal, state and local laws and rules and regulations regarding water quality, hazardous and solid waste management, air quality control and other environmental matters. These laws, rules and regulations require the Partnership to conduct its operations in a specified manner and to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections and other approvals. Failure to comply with applicable environmental laws, rules and regulations may expose the Partnership to significant fines, penalties and/or interruptions in operations. The Partnership's environmental policies and procedures are designed to achieve compliance with such applicable laws and regulations. These evolving laws and regulations and claims for damages to property, employees, other persons and the environment resulting from current or past operations may result in significant expenditures and liabilities in the future.

Predecessor Equity. Predecessor equity included on the consolidated statement of partners' capital and noncontrolling interest represents SUGS member's capital prior to the acquisition date (April 30, 2013).

Revenue Recognition. The Partnership earns revenue from (i) domestic sales of natural gas, NGLs and condensate, (ii) natural gas gathering, processing and transportation, and (iii) contract compression and treating services. Revenue associated with sales of natural gas, NGLs and condensate are recognized when title passes to the customer, which is when the risk of ownership passes to the purchaser and physical delivery occurs. Revenue associated with transportation and processing fees are recognized when the service is provided. For contract compression and contract treating services, revenue is recognized when the service is performed. For gathering and processing services, the Partnership receives either fees or commodities from natural gas producers depending on the type of contract. Commodities received are in turn sold and recognized as revenue in accordance with the criteria outlined above. Under the percentage-of-proceeds contract type, the Partnership is paid for its services by keeping a percentage of the NGLs produced and a percentage of the residue gas resulting from processing the natural gas. Under the percentage-of-index contract type, the Partnership earns revenue by purchasing wellhead natural gas at a percentage of the index price and selling processed natural gas and NGLs at a price approximating the index price to third parties. The Partnership generally reports revenue gross in the consolidated statements of operations when it acts as the principal, takes title to the product, and incurs the risks and rewards of ownership. Revenue for fee-based arrangements is presented net, because the Partnership takes the role of an agent for the producers. Allowance for doubtful accounts is determined based on historical write-off experience and specific identification.

Derivative Instruments. The Partnership's net income and cash flows are subject to volatility stemming from changes in market prices such as natural gas prices, NGLs prices, processing margins and interest rates. The Partnership uses product-specific swaps to create offsetting positions to specific commodity price exposures, and uses interest rate swap contracts to create offsetting positions to specific interest rate exposures. Derivative financial instruments are recorded on the balance sheet at their fair value based on their settlement date. The Partnership employs derivative financial instruments in connection with an underlying asset, liability and/or anticipated transaction and not for speculative purposes. Furthermore, the Partnership regularly assesses the creditworthiness of counterparties to manage the risk of default. Derivative financial instruments qualifying for hedge accounting treatment may be designated by the Partnership as cash flow hedges. The Partnership enters into cash flow hedges to hedge the variability in cash flows related to a forecasted transaction. At inception, the Partnership formally documents the relationship between the hedging instrument and the hedged item, the risk management objectives, and the methods used for assessing and testing correlation and hedge effectiveness. The Partnership also assesses, both at the inception of the hedge and on an on-going basis, whether the derivatives are highly effective in offsetting changes in cash flows of the hedged item. If the Partnership determines that a derivative is no longer highly effective as a hedge, it would discontinues hedge accounting prospectively by including changes in the fair value of the derivative in current earnings. For cash flow hedges, changes in the derivative fair values, to the extent that the hedges are effective, are recorded as a component of accumulated other comprehensive income (loss) until the hedged transactions occur and are recognized in earnings. Any ineffective portion of a cash flow hedge's change in value is recognized immediately in earnings. In the statement of cash flows, the effects of settlements of derivative instruments are classified consistent with the related hedged transactions.

Benefits. The Partnership provides medical, dental, and other healthcare benefits to employees. The total amount incurred by the Partnership for the years ended December 31, 2013, 2012 and 2011, was $9 million, $9 million and $6 million, respectively, in operation and maintenance and general and administrative expenses, as appropriate. The Partnership also provides a matching contribution to its employee's 401(k) accounts. Effective January 1, 2011, the Partnership's 401(k) plan merged with and into that of ETP. As a result of the merger, the Partnership's matching contributions that had not yet fully vested became fully vested. All future matching contributions from the Partnership to the employee 401(k) accounts vest immediately. In addition, SUGS maintained a separate defined contribution plan during March 26, 2012 to December 31, 2012. The total amount of matching contributions for the years ended December 31, 2013, 2012 and 2011 was $7 million, $4 million and $3 million, respectively, and were recorded in operation and maintenance and general and administrative expenses as appropriate. The Partnership has no pension obligations or other post-employment benefits. Beginning January 1, 2013, the Partnership provides a 3% profit sharing contribution to employee 401(k) accounts for all employees with base compensation below a specified threshold. The contribution is in addition to the 401(k) matching contribution and employees become vested based on years of service.

Income Taxes. The Partnership is generally not subject to income taxes, except as discussed below, because its income is taxed directly to its partners. The Partnership is subject to the gross margins tax enacted by the state of Texas. The Partnership has two wholly-owned subsidiaries that are subject to income tax and provides for deferred income taxes using the asset and liability method. Accordingly, deferred taxes are recorded for differences between the tax and book basis that will reverse in future periods. The Partnership has deferred tax liabilities of $22 million as of December 31, 2013 and 2012 related to the difference between the book and tax basis of property, plant and equipment and intangible assets and they are included in other long-term liabilities in the accompanying consolidated balance sheets. The Partnership follows the guidance for uncertainties in income taxes where a liability for an unrecognized tax benefit is recorded for a tax position that does not meet the "more likely than not" criteria. The Partnership has not recorded any uncertain tax positions meeting the more likely than not criteria as of December 31, 2013 and 2012. The Partnership recognized an immaterial amount for current federal income tax expense and deferred income tax benefit for the years ended December 31, 2013, 2012, and 2011.

Although the SUGS operations were included in the Southern Union consolidated federal income tax return prior to the SUGS Acquisition, following their acquisition by the Partnership, SUGS's operations are now treated as a pass-through entity. Therefore, other than one wholly-owned subsidiary, SUGS's historical operations exclude income taxes for all periods presented.

Effective with the Partnership's acquisition of SUGS on April 30, 2013, SUGS is generally no longer subject to federal income taxes and subject only to gross margins tax in the state of Texas. Substantially all previously recorded current and deferred tax liabilities were settled with Southern Union, along with all other intercompany receivables and payables at the date of acquisition.

The IRS commenced audits of our 2007 and 2008 federal income tax returns on January 27, 2010. The IRS has now completed its audit of these returns and proposed certain adjustments. The Partnership filed a protest with the IRS to initiate the appeals process and appeal certain of these adjustments. Until this matter is fully resolved, it is not known whether any amounts ultimately recorded would be material, or how such adjustments would affect unitholders. The statute of limitations for these audits has been extended to December 31, 2014. In January 2014, the Partnership settled the 2007 through 2009 tax returns audit for a wholly-owned subsidiary for an immaterial amount.

Equity-Based Compensation. The Partnership accounts for equity-based compensation by recognizing the grant-date fair value of awards into expense as they are earned, using an estimated forfeiture rate. The forfeiture rate assumption is reviewed annually to determine whether any adjustments to expense are required.

Earnings per Unit. Basic net income per common unit is computed through the use of the two-class method, which allocates earnings to each class of equity security based on their participation in distributions and deemed distributions. Accretion of the Series A Preferred Units is considered as deemed distributions. Distributions and deemed distributions to the Series A Preferred Units reduce the amount of net income available to the general partner and limited partner interests. The general partners' interest in net income or loss consists of its respective percentage interest, make-whole allocations for any losses allocated in a prior tax year and IDRs. After deducting the General Partner's interest, the limited partners' interest in the remaining net income or loss is allocated to each class of equity units based on distributions and beneficial conversion feature amounts, if applicable, then divided by the weighted average number of common and subordinated units outstanding in each class of security. Diluted net income per common unit is computed by dividing limited partners' interest in net income, after deducting the General Partner's interest, by the weighted average number of units outstanding and the effect of non-vested phantom units, Series A Preferred Units and unit options. For special classes of common units, such as the Class F units issued with a beneficial conversion feature, the amount of the benefit associated with the period is added back to net income and the unconverted class is added to the denominator.

3. Partners' Capital and Distributions

Units Activity. The changes in common and Class F units were as follows:

	Common	Class F
Balance - December 31, 2010	137,281,336	—
Common unit offerings, net of costs	20,000,001	—
Issuance of common units under LTIP, net of forfeitures and tax withholding	156,271	—
Balance - December 31, 2011	157,437,608	—
Common unit offerings, net of costs	12,650,000	—
Issuance of common units under the equity distribution agreement, net of cost	691,129	—
Issuance of common units under LTIP, net of forfeitures and tax withholding	172,720	—
Balance - December 31, 2012	170,951,457	—
Issuance of common units under LTIP, net of forfeitures and tax withholding	184,995	—
Issuance of common units under the equity distribution agreement, net of cost	5,712,138	—
Conversion of Series A preferred units for common units	2,629,223	—
Issuance of common units and Class F common units in connection with SUGS Acquisition	31,372,419 (1)	6,274,483 (2)
Balance - December 31, 2013	210,850,232	6,274,483

(1) ETE has agreed to forgo IDR payments on the Partnership common units issued with the SUGS Acquisition for twenty-four months post-transaction closing.
(2) The Class F common units are not entitled to participate in the Partnership's distributions or earnings for twenty-four months post-transaction closing.

Equity Distribution Agreement. In June 2012, the Partnership entered into an Equity Distribution Agreement with Citi under which the Partnership may offer and sell common units, representing limited partner interests, having an aggregate offering price of up to $200 million, from time to time through Citi, as sales agent for the Partnership. Sales of these units, if any, made from time to time under the Equity Distribution Agreement will be made by means of ordinary brokers' transactions on the New York Stock Exchange at market prices, in block transactions, or as otherwise agreed upon by the Partnership and Citi. The Partnership may also sell common units to Citi as principal for its own account at a price agreed upon at the time of sale. Any sale of common units to Citi as principal would be pursuant to the terms of a separate agreement between the Partnership and Citi. The Partnership intends to use the net proceeds from the sale of these units for general partnership purposes. For the years ended December 31, 2013 and 2012, the Partnership received net proceeds of $149 million and $15 million, respectively, from units issued pursuant to this Equity Distribution Agreement. As of December 31, 2013, $34 million remains available to be issued under this agreement.

Public Common Unit Offerings. In March 2012, the Partnership issued 12,650,000 common units representing limited partner interests in a public offering at a price of $24.47 per common unit, resulting in net proceeds of $297 million. In May 2012, the Partnership used the net proceeds from this offering to redeem 35%, or $88 million, in aggregate principal amounts of its outstanding senior notes due 2016; pay related premium, expenses and accrued interest; and repay outstanding borrowings under the revolving credit facility. In August 2010, the Partnership sold 17,537,500 common units and received $408 million in proceeds, inclusive of the General Partner's proportionate capital contribution. In October 2011, the Partnership issued 11,500,000 common units representing limited partnership interests in a public offering at a price of $20.92 per common unit, resulting in net proceeds of $232 million which were used to repay outstanding borrowings under the revolving credit facility.

Private Common Unit Offerings. In May 2011, the Partnership sold 8,500,001 common units representing limited partnership interests resulting in net proceeds of $204 million, to partially fund its capital contribution to Lone Star. These units were issued in a private placement conducted in accordance with the exemption from the registration requirements of the Securities Act of 1933, as amended, under section 4(2) thereof. These units were subsequently registered with the SEC.

Beneficial Conversion Feature. The Partnership issued 6,274,483 Class F common units in connection with the SUGS Acquisition. At the commitment date (February 27, 2013), the sales price of $23.91 per unit represented a $2.19 per unit discount from the fair value of the Partnership's common units as of April 30, 2013. Under FASB ASC 470-20, "*Debt with Conversion and Other Options*," the discount represents a beneficial conversion feature that is treated as a non-cash distribution for purposes of calculating earnings per unit. The beneficial conversion feature is reflected in income per unit using the effective yield method over the period the Class F common units are outstanding, as indicated on the statement of operations in the line item entitled "beneficial conversion feature for Class F common units." The Class F common units are convertible to common units on a one-for-one basis on May 8, 2015.

Noncontrolling Interest. The Partnership operates ELG, a gas gathering joint venture in south Texas in which other third party companies own a 40% interest, which is reflected on the Partnership's consolidated balance sheet as noncontrolling interest.

Distributions. The partnership agreement requires the distribution of all of the Partnership's Available Cash (defined below) within 45 days after the end of each quarter to unitholders of record on the applicable record date, as determined by the General Partner.

Available Cash. Available Cash, for any quarter, generally consists of all cash and cash equivalents on hand at the end of that quarter less the amount of cash reserves established by the general partner to: (i) provide for the proper conduct of the Partnership's business; (ii) comply with applicable law, any debt instruments or other agreements; or (iii) provide funds for distributions to the unitholders and to the General Partner for any one or more of the next four quarters and plus, all cash on hand on that date of determination of available cash for the quarter resulting from working capital borrowings made after the end of the quarter for which the determination is being made.

General Partner Interest and Incentive Distribution Rights. The General Partner is entitled to its proportionate share of all quarterly distributions that the Partnership makes prior to its liquidation. The General Partner has the right, but not the obligation, to contribute a proportionate amount of capital to the Partnership to maintain its current general partner interest. The General Partner's initial 2% interest in these distributions has been reduced since the Partnership has issued additional units and the General Partner has not contributed a proportionate amount of capital to the Partnership to maintain its General Partner interest. The General Partner ownership interest as of December 31, 2013 was 1.3%. This General Partner interest is represented by 2,834,381 equivalent units as of December 31, 2013.

The IDRs held by the General Partner entitle it to receive an increasing share of Available Cash when pre-defined distribution targets are achieved. The General Partner's IDRs are not reduced if the Partnership issues additional units in the future and the general partner does not contribute a proportionate amount of capital to the Partnership to maintain its general partner interest.

In connection with the SUGS Acquisition, ETE agreed to forgo IDR payments on the Partnership common units issued with this transaction for the twenty-four months post-transaction closing.

Distributions. The Partnership made the following cash distributions per unit during the years ended December 31, 2013 and 2012:

Distribution Date	Cash Distribution (per common unit)
November 14, 2013	$ 0.470
August 14, 2013	0.465
May 13, 2013	0.460
February 14, 2013	0.460
November 14, 2012	$ 0.460
August 14, 2012	0.460
May 14, 2012	0.460
February 13, 2012	0.460

The Partnership paid a cash distribution of $0.475 per common unit on February 14, 2014.

4. Income per Limited Partner Unit

The following table provides a reconciliation of the numerator and denominator of the basic and diluted earnings per unit computations for the years ended December 31, 2013, 2012, and 2011.

	For the Years Ended December 31,								
	2013			2012			2011		
	Income (Numerator)	Units (Denominator)	Per-Unit Amount	Income (Numerator)	Units (Denominator)	Per-Unit Amount	Income (Numerator)	Units (Denominator)	Per-Unit Amount
Basic income per unit									
Limited Partners' interest in net income	$ 34	196,227,348	$ 0.17	$ 27	167,492,735	$ 0.16	$ 57	145,490,869	$ 0.39
Effect of Dilutive Securities:									
Common unit options	—	22,714		—	10,854		—	19,192	
Phantom units *	—	357,230		—	223,325		—	148,388	
Series A Preferred Units	—	2,050,854		(5)	4,658,700		(10)	4,632,389	
Diluted income per unit	$ 34	198,658,146	$ 0.17	$ 22	172,385,614	$ 0.13	$ 47	150,290,838	$ 0.32

* Amount assumes maximum conversion rate for market condition awards.

There were no securities that could potentially dilute earnings per unit in the future that were not included in the computation of diluted earnings per unit.

The partnership agreement requires that the General Partner shall receive a 100% allocation of income until its capital account is made whole for all of the net losses allocated to it in prior years.

5. Acquisitions and Dispositions

2013

SUGS Acquisition. The SUGS Acquisition is discussed in footnote 1 - Organization and Basis of Presentation.

PVR Acquisition. In October 2013, the Partnership announced that it entered into a merger agreement with PVR ("PVR Acquisition") pursuant to which the Partnership intends to merge with PVR. This merger will be a unit-for-unit transaction plus a one-time $37 million cash payment to PVR unitholders which represents total consideration of $5.6 billion, including the assumption of net debt of $1.8 billion. The holders of PVR common units, PVR Class B Units and PVR Special Units ("PVR Unit(s)") will receive 1.02 Partnership common units in exchange for each PVR Unit held on the applicable record date. In November 2013, the Partnership received approval of the PVR Acquisition under the Hart-Scott-Rodino Antitrust Improvements Act. The transaction is subject to the approval of PVR's unitholders and other customary closing conditions, and is expected to close in March 2014.

The PVR Acquisition is expected to enhance our geographic diversity with a strategic presence in the Marcellus and Utica shales in the Appalachian Basin and the Granite Wash in the Mid-Continent region.

Eagle Rock Acquisition. In December, 2013, the Partnership entered into an agreement to purchase Eagle Rock's midstream business (the "Eagle Rock Midstream Acquisition") for approximately $1.3 billion. This acquisition is expected to complement the Partnership's core gathering and processing business, and when combined with the PVR Acquisition, is expected to further diversify the Partnership's basin exposure in the Texas Panhandle, east Texas and south Texas. The Eagle Rock Midstream Acquisition is expected to close in the second quarter of 2014, and is subject to the approval of Eagle Rock unitholders, Hart-Scott-Rodino Antitrust Improvements Act approval and other customary closing conditions.

Hoover Energy Acquisition. On February 3, 2014, the Partnership completed its previously announced acquisition of the subsidiaries of Hoover that are engaged in crude oil gathering, transportation and terminaling, condensate handling, natural gas gathering, treating and processing, and water gathering and disposal services in the southern Delaware Basin in west Texas. The consideration paid by the Partnership was valued at $281.6 million (subject to customary post-closing adjustments) and consisted of (i) 4,040,471 common units issued to Hoover and (ii) $183.6 million in cash. A portion of the consideration is being held in escrow as security for certain indemnification claims. The Partnership financed the cash portion of the purchase price through borrowings under its revolving credit facility. The Partnership will account for the acquisition of Hoover using the acquisition method of accounting, which requires, among other things, that assets acquired and liabilities assumed be recognized on the balance sheet at their fair values as of the acquisition date. Management's evaluation of the assigned fair values is ongoing as the transaction was recently completed and therefore the Partnership was not able to complete the preliminary allocation of the purchase price to the acquired assets and liabilities prior to the issuance of these financial statements.

2011

Lone Star. On May 2, 2011, the Partnership contributed $593 million in cash to Lone Star, in exchange for its 30% interest. Lone Star, a newly formed joint venture that is owned 70% by ETP and 30% by the Partnership, completed its acquisition of all of the membership interest in LDH, a wholly-owned subsidiary of Louis Dreyfus Highbridge Energy LLC for $1.98 billion in cash. To fund a portion of this capital contribution, the Partnership issued 8,500,001 common units representing limited partnership interests with net proceeds of $204 million. The remaining portion of the Partnership's capital contribution was funded by additional borrowings under its revolving credit facility.

Ranch JV. On December 2, 2011, Ranch JV was formed by the Partnership, APM and CM, each owning a 33.33% interest in the joint venture. Ranch JV processes natural gas delivered from the NGLs-rich Bone Spring and Avalon shale formations in west Texas.

6. Investments in Unconsolidated Affiliates

As of December 31, 2013, the Partnership has a 49.99% general partner interest in HPC, a 50% membership interest in MEP, a 30% membership interest in Lone Star, a 33.33% membership interest in Ranch JV, and a 50% membership interest in Grey Ranch. The Partnership acquired a 33.33% membership interest in Ranch JV in December 2011, a 30% interest in Lone Star in May 2011, a 49.9% interest in MEP in May 2010 and a 0.1% interest in MEP in September 2011. The carrying value of the Partnership's investment in each of the unconsolidated affiliates as of December 31, 2013 and 2012 is as follows:

	December 31,	
	2013	2012
HPC	$ 442	$ 650
MEP	548	581
Lone Star	1,070	948
Ranch JV	36	35
Grey Ranch	1	—
	$ 2,097	$ 2,214

The following tables summarize the changes in the Partnership's investment activities in each of the unconsolidated affiliates for the years ended December 31, 2013, 2012 and 2011:

	Year Ended December 31, 2013				
	HPC [2]	MEP	Lone Star	Ranch JV	Grey Ranch
Contributions	$ —	$ —	$ 137	$ 2	$ —
Distributions	238	72	79	2	—
Share of net income	36	39	64	1	1
Amortization of excess fair value of investment [1]	(6)	—	—	—	—

	Year Ended December 31, 2012				
	HPC	MEP	Lone Star	Ranch JV	Grey Ranch
Contributions	$ —	$ —	$ 343	$ 36	$ —
Distributions	61	75	68	—	—
Share of net income	35	42	44	(1)	(9)
Amortization of excess fair value of investment [1]	(6)	—	—	—	—

	Year Ended December 31, 2011				
	HPC	MEP[3]	Lone Star[4]	Ranch JV	Grey Ranch
Contributions	$ —	$ —	$ 645	$ —	N/A
Purchase of additional interest	—	1	—	—	N/A
Distributions	65	83	22	—	N/A
Return of investment	—	—	23	—	N/A
Share of net income	55	43	28	—	N/A
Amortization of excess fair value of investment [1]	(6)	—	—	—	N/A

(1) The Partnership's investment in HPC was adjusted to its fair value on May 26, 2010 and the excess fair value over net book value was comprised of two components: (1) $155 million was attributed to HPC's long-lived assets and is being amortized as a reduction of income from unconsolidated affiliates over the useful lives of the respective assets, which vary from 15 to 30 years, and (2) $32 million could not be attributed to a specific asset and therefore will not be amortized in future periods.

(2) HPC entered into a $500 million 5-year revolving credit facility in September 2013, pursuant to which the Partnership pledged its 49.99% equity interest in HPC. Upon closing such credit facility, HPC borrowed $370 million to fund a non-recurring return of investment to its partners of which the Partnership received $185 million. The amount outstanding under this facility was $445 million as of December 31, 2013. The Partnership's contingent obligation with respect to the outstanding borrowings under this facility was $222 million at December 31, 2013.

(3) In September 2011, the Partnership purchased an additional 0.1% interest in MEP from ETP for $1 million in cash, bringing the total membership interest to 50%.

(4) For the period from initial contribution, May 2, 2011, to December 31, 2011.

N/A The Partnership acquired a 50% interest in Grey Ranch in March 2012, as part of the SUGS Acquisition in April 2013.

7. Derivative Instruments

Policies. The Partnership established comprehensive risk management policies and procedures to monitor and manage the market risks associated with commodity prices, counterparty credit, and interest rates. The General Partner is responsible for delegation of transaction authority levels, and the Audit and Risk Committee of the General Partner is responsible for the overall management of these risks, including monitoring exposure limits. The Audit and Risk Committee receives regular briefings on exposures and overall risk management in the context of market activities.

Commodity Price Risk. The Partnership is a net seller of NGLs, condensate and natural gas as a result of its gathering and processing operations. The prices of these commodities are impacted by changes in the supply and demand as well as other market forces. Both the Partnership's profitability and cash flow are affected by the inherent volatility of these commodities which could adversely affect its ability to make distributions to its unitholders. The Partnership manages this commodity price exposure through an integrated strategy that includes management of its contract portfolio, matching sales prices of commodities with purchases, optimization of its portfolio by monitoring basis and other price differentials in operating areas, and the use of derivative contracts. In some cases, the Partnership may not be able to match pricing terms or to cover its risk to price exposure with financial hedges, and it may be exposed to commodity price risk. Speculative positions with derivative contracts are prohibited under the Partnership's policies.

The Partnership has swap contracts settled against NGLs (propane, butane, and natural gasoline), condensate and natural gas market prices. The Partnership also had put options settled against ethane, which expired in December 2012.

On January 1, 2012, the Partnership de-designated its swap contracts and began accounting for these contracts using the mark-to-market method of accounting. As of December 31, 2013, the Partnership had an immaterial amount in net hedging gains in AOCI, all of which will be amortized to earnings over the next three months.

As of December 31, 2012, SUGS had outstanding receive-fixed natural gas price swaps with a total notional amount of 4,562,500 MMBtu for 2012. These natural gas price swaps were accounted for as cash flow hedges, with effective portion of changes in their fair value recorded to AOCI and reclassified into revenues in the same period which the forecasted natural gas sales impact earnings. As of April 30, 2013, in connection with the SUGS Acquisition, these outstanding hedges were terminated.

Interest Rate Risk. The Partnership is exposed to variable interest rate risk as a result of borrowings under its revolving credit facility. The Partnership's $250 million interest rate swaps expired in April 2012. As of December 31, 2013, the Partnership had $510 million of outstanding borrowings exposed to variable interest rate risk.

Credit Risk. The Partnership's resale of NGLs, condensate, and natural gas exposes it to credit risk, as the margin on any sale is generally a very small percentage of the total sales price. Therefore, a credit loss can be very large relative to overall profitability on these transactions. The Partnership monitors credit exposure and attempts to ensure that it issues credit only to creditworthy counterparties and that in appropriate circumstances any such extension of credit is backed by adequate collateral, such as a letter of credit or parental guarantee from a parent company with potentially better credit.

The Partnership is exposed to credit risk from its derivative counterparties. The Partnership does not require collateral from these counterparties. The Partnership deals primarily with financial institutions when entering into financial derivatives, and utilizes master netting agreements that allow for netting of swap contract receivables and payables in the event of default by either party. If the Partnership's counterparties failed to perform under existing swap contracts, the Partnership's maximum loss as of December 31, 2013 was $4 million, which would be reduced by less than $1 million due to the netting feature. The Partnership has elected to present assets and liabilities under master netting agreements gross on the consolidated balance sheets.

Embedded Derivatives. The Series A Preferred Units contain embedded derivatives which are required to be bifurcated and accounted for separately, such as the holders' conversion option and the Partnership's call option. These embedded derivatives are accounted for using mark-to-market accounting. The Partnership does not expect the embedded derivatives to affect its cash flows.

The Partnership's derivative assets and liabilities, including credit risk adjustments, as of December 31, 2013 and 2012 are detailed below:

	Assets		Liabilities	
	December 31,		December 31,	
	2013	2012	2013	2012
Derivatives designated as cash flow hedges				
Current amounts				
Commodity contracts	$ —	$ —	$ —	$ 5
Total cash flow hedging instruments	—	—	—	5
Derivatives not designated as cash flow hedges				
Current amounts				
Commodity contracts	$ 3	$ 4	$ 9	$ 1
Long-term amounts				
Commodity contracts	1	1	—	—
Embedded derivatives in Series A Preferred Units	—	—	19	25
Total derivatives	$ 4	$ 5	$ 28	$ 31

The Partnership's statements of operations for the years ended December 31, 2013, 2012 and 2011 were impacted by derivative instruments activities as detailed below:

		Years Ended December 31,		
		2013	2012	2011
Derivatives in cash flow hedging relationships:		Change in Value Recognized in AOCI on Derivatives (Effective Portion)		
Commodity derivatives		$ —	$ (4)	$ (13)
Derivatives in cash flow hedging relationships:	**Location of Gain/(Loss) Recognized in Income**	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)		
Commodity derivatives	Revenue	$ —	$ 6	$ (19)

		Years Ended December 31,		
		2013	2012	2011
Derivatives not designated in a hedging relationship:	**Location of Gain/(Loss) Recognized in Income**	Amount of Gain/(Loss) from De-designation Amortized from AOCI into Income		
Commodity derivatives	Revenue	$ —	$ (5)	$ —
Derivatives not designated in a hedging relationship:	**Location of Gain/(Loss) Recognized in Income**	Amount of Gain/(Loss) Recognized in Income on Derivatives		
Commodity derivatives	Revenue	$ (9)	$ 16	$ —
Embedded derivatives	Other income & deductions	6	14	18
		$ (3)	$ 30	$ 18

8. Long-term Debt

Obligations in the form of senior notes and borrowings under the credit facilities are as follows:

	December 31,	
	2013	2012
Senior notes	$ 2,800	$ 1,965
Revolving loans	510	192
Total	3,310	2,157
Less: current portion	—	—
Long-term debt	$ 3,310	$ 2,157
Availability under revolving credit facility:		
Total credit facility limit	$ 1,200	$ 1,150
Revolving loans	(510)	(192)
Letters of credit	(14)	(12)
Total available	$ 676	$ 946

Long-term debt maturities as of December 31, 2013 for each of the next five years are as follows:

Year Ended December 31,	Amount
2014	$ —
2015	—
2016	—
2017	—
2018	600
Thereafter	2,710
Total	$ 3,310

Revolving Credit Facility

In the year ended December 31, 2013, 2012 and 2011 the Partnership borrowed $1.43 billion, $1.56 billion and $940 million, respectively, under its revolving credit facility; these borrowings were to fund capital expenditures and acquisitions. During the same periods, the Partnership repaid $1.1 billion, $1.70 billion and $893 million, respectively, with proceeds from equity offerings and issuances of senior notes.

In May 2013, RGS entered into the Sixth Amended and Restated Credit Agreement to increase the commitment to $1.2 billion with a $300 million uncommitted incremental facility and extended the maturity date to May 21, 2018. The material differences between the Fifth and Sixth Amended and Restated Credit Agreement include:

- A 75 bps decrease in pricing, with an additional 50 bps decrease upon the achievement of an investment grade rating;
- No limitation on the maximum amount that the loan parties may invest in joint ventures existing on the date of the credit agreement so long as the Partnership is in pro forma compliance with the financial covenants;
- The addition of a "Restricted Subsidiary" structure such that certain designated subsidiaries are not subject to the credit facility covenants and do not guarantee the obligations thereunder or pledge their assets in support thereof;
- The addition of provisions such that upon the achievement of an investment grade rating by the Partnership, the collateral package will be released; the facility will become unsecured; and the covenant package will be significantly reduced;
- An eight-quarter increase in the permitted Total Leverage Ratio; and
- After March 2015, an increase in the permitted total leverage ratio for the two fiscal quarters following any $50 million or greater acquisition.

The Partnership capitalized $6 million of net loan fees which is being amortized over the remaining term.

The revolving credit facility and the guarantees are senior to the Partnership's and the guarantors' unsecured obligations, to the extent of the value of the assets securing such obligations.

As of December 31, 2013, the Partnership was in compliance in all material respects with all of the financial covenants contained within the new credit agreement.

The outstanding balance under the revolving credit facility bears interest at LIBOR plus a margin or alternate base rate (equivalent to the U.S. prime lending rate) plus a margin, or a combination of both. The alternate base rate used to calculate interest on base rate loans will be calculated based on the greatest to occur of a base rate, a federal funds effective rate plus 0.50% and an adjusted one-month LIBOR rate plus 1.00%. The applicable margin shall range from 0.625% to 1.50% for base rate loans, 1.625% to 2.50% for Eurodollar loans. The weighted average interest rate on the total amounts outstanding under the Partnership's revolving credit facility was 2.17% and 2.93% as of December 31, 2013 and 2012, respectively.

RGS must pay (i) a commitment fee ranging from 0.30% to 0.45% per annum of the unused portion of the revolving loan commitments, (ii) a participation fee for each revolving lender participating in letters of credit ranging from 1.625% to 2.50% per annum of the average daily amount of such lender's letter of credit exposure and (iii) a fronting fee to the issuing bank of letters of credit equal to 0.20% per annum of the average daily amount of the letter of credit exposure. These fees are included in interest expense, net in the consolidated statement of operations.

The revolving credit facility contains financial covenants requiring RGS and its subsidiaries to maintain a debt to consolidated EBITDA (as defined in the credit agreement) ratio less than 5.00 for the first eight quarters (after March 2015, an increase is allowed in the permitted total leverage ratio for the first two fiscal quarters following any $50 million or greater acquisition), consolidated EBITDA to consolidated interest expense ratio greater than 2.50 and a secured debt to consolidated EBITDA ratio less than 3.25. At December 31, 2013 and 2012, RGS and its subsidiaries were in compliance with these covenants.

The revolving credit facility restricts the ability of RGS to pay dividends and distributions other than reimbursements of the Partnership for expenses and payment of dividends to the Partnership to the amount of available cash (as defined) so long as no default or event of default has occurred or is continuing. The revolving credit facility also contains various covenants that limit (subject to certain exceptions), among other things, the ability of RGS to:

- incur indebtedness;
- grant liens;
- enter into sale and leaseback transactions;
- make certain investments, loans and advances;
- dissolve or enter into a merger or consolidation;
- enter into asset sales or make acquisitions;
- enter into transactions with affiliates;
- prepay other indebtedness or amend organizational documents or transactions documents (as defined in the revolving credit facility);
- issue capital stock or create subsidiaries; or

- engage in any business other than those businesses in which it was engaged at the time of the effectiveness of the revolving credit facility or reasonable extension thereof.

In February 2014, RGS entered into the first Amendment to the Sixth Amended and restated Credit Agreement to, among other things, expressly permit the pending PVR and Eagle Rock acquisitions, and to increase the commitment to $1.5 billion and increase the uncommitted incremental facility to $500 million. The amendment will specifically allows the Partnership to assume the series of PVR senior notes that mature prior to the credit agreement.

Senior Notes

In May 2009, the Partnership and Finance Corp. issued $250 million of senior notes that mature on June 1, 2016 (the “2016 Notes”). The 2016 Notes bear interest at 9.375% with interest payable semi-annually in arrears on June 1 and December 1. In May 2012, the Partnership redeemed 35%, or $88 million, of the 2016 Notes, bringing the total outstanding principal amount to $163 million. A redemption premium of $8 million was charged to loss on debt refinancing, net in the consolidated statement of operations and $4 million of accrued interest was paid. The Partnership also wrote off the unamortized loan fee of $1 million and unamortized bond premium of $2 million to loss on debt refinancing, net in the consolidated statement of operations. In June 2013, the Partnership redeemed all amounts outstanding 2016 Notes for $178 million cash, inclusive of accrued and unpaid interest of $7 million and other fees and expenses.

The Partnership and Finance Corp. have outstanding the following series of senior notes (collectively “Senior Notes”):

- $600 million in aggregate principal amount of our 6.875% senior notes due December 1, 2018 (the “2018 Notes”) with interest payable semi-annually in arrears on June 1 and December 1;
- $400 million in aggregate principal amount of our 5.75% senior notes due September 1, 2020 (the “2020 Notes”) with interest payable semi-annually in arrears on March 1 and September 1;
- $500 million in aggregate principal amount of our 6.5% senior notes due July 15, 2021 (the “2021 Notes”) with interest payable semi-annually in arrears on January 15 and July 15;
- $900 million in aggregate principal of our 5.875% senior notes due March 1, 2022 (the “2022 Notes”), issued in February 2014, with interest payable semi-annually in arrears on March 1 and September 1;
- $700 million in aggregate principal amount of our 5.5% senior notes due April 15, 2023 (the “2023 5.5% Notes”) with interest payable semi-annually in arrears on April 15 and October 15; and
- $600 million in aggregate principal amount of our 4.5% senior notes due November 1, 2023 (the “2023 4.5% Notes”) with interest payable semi-annually in arrears on May 1 and November 1.

The Senior Notes are guaranteed by our existing consolidated subsidiaries except Finance Corp and ELG.

The Senior Notes are redeemable at any time prior to the dates specified below at a price equal to 100% of the principal amount of the applicable series, plus a make-whole premium and accrued and unpaid interest, if any, to the redemption date.

- 2018 Notes - Beginning December 1, 2014 100% may be redeemed at fixed redemption price of 103.438% (December 1, 2015 - 101.719% and December 1, 2016 and thereafter - 100%) plus accrued and unpaid interest, if any, to the redemption date
- 2020 Notes - Redeemable, in whole or in part, prior to June 1, 2020 at 100% of the principal amount plus a make-whole premium and accrued and unpaid interest, if any, to the redemption date; redeemable, in whole or in part, on or after June 1, 2020 at 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date
- 2021 Notes - Any time prior to July 15, 2014, up to 35% may be redeemed at a price of 106.5% plus accrued and unpaid interest, if any; beginning July 15, 2016, 100% may be redeemed at fixed redemption price of 103.25% (July 15, 2017 - 102.167%, July 15, 2018 - 101.083% and July 15, 2019 and thereafter - 100%) plus accrued and unpaid interest, if any, to the redemption date
- 2022 Notes - Redeemable, in whole or in part, prior to December 1, 2021 at 100% at the principal amount plus a make-whole premium and accrued and unpaid interest, if any, to the redemption date; redeemable, in whole or in part, on or after December 1, 2021 at 100% at the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date
- 2023 5.5% Notes - Any time prior to October 15, 2015, up to 35% may be redeemed at a price of 105.5% plus accrued and unpaid interest, if any; beginning October 15, 2017, 100% may be redeemed at fixed redemption price of 102.75% (October 15, 2018 - 101.833%, October 15, 2019 - 100.917% and October 15, 2020 and thereafter - 100%) plus accrued and unpaid interest, if any, to the redemption date
- 2023 4.5% Notes - Redeemable, in whole or in part, prior to August 1, 2023 at 100% of the principal amount plus a make-whole premium and accrued and unpaid interest, if any, to the redemption date; redeemable, in whole or in part, on or

after August 1, 2023 at 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date

Upon a change of control followed by a ratings downgrade within 90 days of a change of control, each note holder of the Senior Notes will be entitled to require us to purchase all or a portion of its notes at a purchase price of 101% plus accrued and unpaid interest, if any. The Partnership's ability to purchase the Senior Notes upon a change of control will be limited by the terms of our debt agreements, including the Partnership's revolving credit facility.

The existing senior notes contain various covenants that limit, among other things, our ability, and the ability of certain of our subsidiaries, to:

- incur additional indebtedness;
- pay distributions on, or repurchase or redeem our equity interests;
- make certain investments;
- incur liens;
- enter into certain types of transactions with affiliates; and
- sell assets or consolidate or merge with or into other companies.

If the Senior Notes achieve investment grade ratings by both Moody's and Standard & Poor's and no default or event of default has occurred and is continuing, we will no longer be subject to many of the foregoing covenants. At December 31, 2013, we were in compliance with these covenants.

9. Intangible Assets

Activity related to intangible assets, net consisted of the following:

	Customer Relations	Trade Names	Total
Balance at January 1, 2012	$ 681	$ 60	$ 741
Amortization	(26)	(3)	(29)
Balance at December 31, 2012	655	57	712
Amortization	(26)	(4)	(30)
Balance at December 31, 2013	$ 629	$ 53	$ 682

The average remaining amortization periods for customer relations and trade names are 24 and 16 years, respectively. The expected amortization of the intangible assets for each of the five succeeding years is $30 million.

10. Fair Value Measures

The fair value measurement provisions establish a three-tiered fair value hierarchy that prioritizes inputs to valuation techniques used in fair value calculations. The three levels of inputs are defined as follows:

- Level 1—unadjusted quoted prices for identical assets or liabilities in active accessible markets;
- Level 2—inputs that are observable in the marketplace other than those classified as Level 1; and
- Level 3—inputs that are unobservable in the marketplace and significant to the valuation.

Entities are encouraged to maximize the use of observable inputs and minimize the use of unobservable inputs. If a financial instrument uses inputs that fall in different levels of the hierarchy, the instrument will be categorized based upon the lowest level of input that is significant to the fair value calculation.

The Partnership's financial assets and liabilities measured at fair value on a recurring basis are derivatives related to commodity swaps and embedded derivatives in the Series A Preferred Units. Derivatives related to commodity swaps are valued using observable inputs for similar instruments and incorporate Level 1 and Level 2 inputs. Embedded derivatives related to the Series A Preferred Units are valued using a binomial lattice model. The market inputs utilized in the model include credit spread, probabilities of the occurrence of certain events, common unit price, dividend yield, and expected volatility, and are classified as Level 3.

The following table presents the Partnership’s derivative assets and liabilities measured at fair value on a recurring basis:

	Fair Value Measurement at December 31,					
	2013			2012		
	Fair Value Total	Level 2	Level 3	Fair Value Total	Level 2	Level 3
Assets						
Commodity Derivatives:						
Natural Gas	$ 2	$ 2	$ —	$ 2	$ 2	$ —
Natural Gas Liquids	2	2	—	1	1	—
Condensate	—	—	—	2	2	—
Total Assets	$ 4	$ 4	$ —	$ 5	$ 5	$ —
Liabilities						
Commodity Derivatives:						
Natural Gas	$ 4	$ 4	$ —	$ 5	$ 5	$ —
Natural Gas Liquids	4	4	—	1	1	—
Condensate	1	1	—	—	—	—
Embedded Derivatives in Series A Preferred Units	19	—	19	25	—	25
Total Liabilities	$ 28	$ 9	$ 19	$ 31	$ 6	$ 25

The following table presents the material unobservable inputs used to estimate the fair value of the embedded derivatives in the Series A Preferred Units:

Unobservable Input	December 31, 2013
Credit Spread	4.16%
Volatility	23.71%

Changes in the Partnership's cost of equity and U.S. Treasury yields would cause a change in the credit spread used to value the embedded derivatives. Changes in the Partnership's historical unit price volatility would cause a change in the volatility used to value the embedded derivatives.

The following table presents the changes in Level 3 derivatives measured on a recurring basis for the years ended December 31, 2013 and 2012. There were no transfers between Level 2 and Level 3 derivatives for the years ended December 31, 2013 and 2012.

	Embedded Derivatives in Series A Preferred Units
Balance at January 1, 2012	$ 39
Change in fair value	(14)
Balance at December 31, 2012	25
Change in fair value, net of gain at conversion of $26 million	(6)
Balance at December 31, 2013	$ 19

The carrying amount of cash and cash equivalents, accounts receivable and accounts payable approximates fair value due to their short-term maturities. Long-term debt, other than the Senior Notes, is comprised of borrowings under which interest accrues under a floating interest rate structure. Accordingly, the carrying value approximates fair value.

The aggregate fair value and carrying amount of the Senior Notes at December 31, 2013 was $2.83 billion and $2.80 billion, respectively. As of December 31, 2012, the aggregate fair value and carrying amount of the Senior Notes was $2.13 billion and $1.97 billion, respectively. The fair value of the Senior Notes is a Level 1 valuation based on third party market value quotations.

11. Leases

The following table is a schedule of future minimum lease payments for office space and certain equipment leased by the Partnership, that had initial or remaining non-cancelable lease terms in excess of one year as of December 31, 2013:

For the year ending December 31,	Operating Lease
2014	$ 3
2015	3
2016	2
2017	2
2018	2
Thereafter	34
Total minimum lease payments	$ 46

Total rent expense for operating leases, including those leases with terms of less than one year, was $11 million, $11 million and $3 million for the years ended December 31, 2013, 2012 and 2011, respectively.

12. Commitments and Contingencies

Legal. The Partnership is involved in various claims, lawsuits and audits by taxing authorities incidental to its business. These claims and lawsuits in the aggregate are not expected to have a material adverse effect on the Partnership's business, financial condition, results of operations or cash flows.

PVR Shareholder Litigation. Five putative class action lawsuits challenging the PVR Acquisition are currently pending. All of the cases name PVR, PVR GP and the current directors of PVR GP, as well as the Partnership and the General Partner (collectively, the "Regency Defendants"), as defendants. Each of the lawsuits has been brought by a purported unitholder of PVR, both individually and on behalf of a putative class consisting of public unitholders of PVR. The lawsuits generally allege, among other things, that the directors of PVR GP breached their fiduciary duties to unitholders of PVR, that PVR GP, PVR and the Regency Defendants aided and abetted the directors of PVR GP in the alleged breach of these fiduciary duties, and, as to the actions in federal court, that some or all of PVR, PVR GP, and the directors of PVR GP violated Section 14(a) of the Exchange Act and Rule 14a-9 promulgated thereunder and Section 20(a) of the Exchange Act. The lawsuits purport to seek, in general, (i) injunctive relief, (ii) disclosure of certain additional information concerning the transaction, (iii) in the event the merger is consummated, rescission or an award of rescissory damages, (iv) an award of plaintiffs' costs and (v) the accounting for damages allegedly causes by the defendants to these actions, and, (iv) such further relief as the court deems just and proper. The styles of the pending cases are as follows: David Naiditch v. PVR Partners, L.P., et al. (Case No. 9015-VCL) in the Court of Chancery of the State of Delaware); Charles Monatt v. PVR Partners, LP, et al. (Case No. 2013-10606) and Saul Srour v. PVR Partners, L.P., et al. (Case No. 2013-011015), each pending in the Court of Common Pleas for Delaware County, Pennsylvania; Stephen Bushansky v. PVR Partners, L.P., et al. (C.A. No. 2:13-cv-06829-HB); and Mark Hinnau v. PVR Partners, L.P., et al. (C.A. No. 2:13-cv-07496-HB), pending in the United States District Court for the Eastern District of Pennsylvania.

On January 28, 2014, the defendants entered into a Memorandum of Understanding ("MOU") with Monatt, Srour, Bushansky, Naiditch and Hinnau pursuant to which defendants and the referenced plaintiffs agreed in principle to a settlement of their lawsuits ("Settled Lawsuits"), which will be memorialized in a separate settlement agreement, subject to customary conditions, including consummation of the PVR Acquisition, completion of certain confirmatory discovery, class certification and final approval by the Court of Common Pleas for Delaware County, Pennsylvania. If the Court approves the settlement, the Settled Lawsuits will be dismissed with prejudice and all defendants will be released from any and all claims relating to the Settled Lawsuits.

The settlement will not affect any provisions of the merger agreement or the form or amount of consideration to be received by PVR unitholders in the PVR Acquisition. The defendants have denied and continue to deny any wrongdoing or liability with respect to the plaintiffs' claims in the aforementioned litigation and have entered into the settlement to eliminate the uncertainty, burden, risk, expense, and distraction of further litigation.

Environmental. The Partnership is responsible for environmental remediation at certain sites on its gathering and processing systems, resulting primarily from releases of hydrocarbons. The Partnership's remediation program typically involves the management of contaminated soils and may involve remediation of groundwater. Activities vary with site conditions and locations, the extent and nature of the contamination, remedial requirements and complexity. The ultimate liability and total costs associated with these sites will depend upon many factors.

The table below reflects the environmental liabilities recorded in the consolidated balance sheet at December 31, 2013 and 2012 where management believes a loss is probable and reasonably estimable. The Partnership does not have any material environmental remediation matters assessed as reasonably possible that would require disclosure in the financial statements.

	December 31,	
	2013	2012
Current	$ 2	$ 5
Noncurrent	6	7
Total environmental liabilities	$ 8	$ 12

The Partnership made expenditures related to environmental remediation of $5 million for the year ended December 31, 2013.

Air Quality Control. The Partnership is currently negotiating settlements to certain enforcement actions by the NMED and the TCEQ. The TCEQ recently initiated a state-wide emissions inventory for the sulfur dioxide emissions from sites with reported emissions of 10 tons per year or more. If this data demonstrates that any source or group of sources may cause or contribute to a violation of the National Ambient Air Quality Standards, they must be sufficiently controlled to ensure timely attainment of the standard. This may potentially affect three SUGS recovery units in Texas. It is unclear at this time how the NMED will address the sulfur dioxide standard.

Compliance Orders from the NMED. SUGS has been in discussions with the NMED concerning allegations of violations of New Mexico air regulations related to the Jal #3 and Jal #4 facilities. Hearings on the COs were delayed until March 2014 to allow the parties to pursue substantive settlement discussions. The Partnership has meritorious defenses to the NMED claims and can offer significant mitigating factors to the claimed violations. The Partnership has recorded a liability of less than $1 million related to the claims and will continue to assess its potential exposure to the allegations as the matters progress.

CDM Sales Tax Audit. CDM Resource Management LLC (“CDM”), a subsidiary of the Partnership, has historically claimed the manufacturing exemption from sales tax in Texas, as is common in the industry. The exemption is based on the fact that CDM's natural gas compression equipment is used in the process of treating natural gas for ultimate use and sale. In a recent audit by the Texas Comptroller's office, the Comptroller has challenged the applicability of the manufacturing exemption to CDM. The period being audited is from August 2006 to August 2007, and liability for that period is potentially covered by an indemnity obligation from CDM's prior owners. CDM may also have liability for periods since 2008, and prospectively, if the Comptroller's challenge is ultimately successful. An audit of the 2008 period has commenced. In April 2013, an independent audit review agreed with the Comptroller's position. While CDM continues to disagree with this position and intends to seek redetermination and other relief, the Partnership is unable to predict the final outcome of this matter.

In addition to the matters discussed above, the Partnership is involved in legal, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies regarding matters arising in the ordinary course of business, none of which are believed to be potentially material to the Partnership at this time.

13. Series A Preferred Units

On September 2, 2009, the Partnership issued 4,371,586 Series A Preferred Units at a price of $18.30 per unit, less issuance costs and a 4% discount of $3 million for net proceeds of $77 million, exclusive of the General Partner’s contribution of $2 million. The Series A Preferred Units are convertible to common units under terms described below, and if outstanding, are mandatorily redeemable on September 2, 2029 for $35 million plus all accrued but unpaid distributions thereon (the “Series A Liquidation Value”) and accrued interest. The Series A Preferred Units receive fixed quarterly cash distributions of $0.445 per unit which began with the quarter ending March 31, 2010.

Holders may elect to convert Series A Preferred Units to common units at any time. In July 2013, certain holders of Series A Preferred Units exercised their right to convert 2,459,017 Series A Preferred Units into common units. Concurrent with this transaction, the Partnership recognized a $26 million gain in other income and deductions, net, related to the embedded derivative and reclassified $41 million from the Series A Preferred Units into common units. As of December 31, 2013, the remaining Series A Preferred Units were convertible into 2,050,854 common units, and if outstanding, are mandatorily redeemable on September 2, 2029 for $35 million plus all accrued but unpaid distributions and interest thereon. The Series A Preferred Units receive fixed quarterly cash distributions of $0.445 per unit if outstanding on the record dates of the Partnership’s common unit distributions.

Distributions on the Series A Preferred Units were accrued for the first two quarters (and not paid in cash) and will result in an increase in the number of common units issuable upon conversion. If on any distribution payment date beginning March 31, 2010, the Partnership (1) fails to pay distributions on the Series A Preferred Units, (2) reduces the distributions on the common units to zero and (3) is prohibited by its material financing agreements from paying cash distributions, such distributions shall automatically accrue and accumulate until paid in cash. If the Partnership has failed to pay cash distributions in full for two quarters (whether or not consecutive) from and including the quarter ended on March 31, 2010, then if the Partnership fails to pay cash distributions on the Series A Preferred Units, all future distributions on the Series A Preferred Units that are accrued rather than being paid in cash by the Partnership will consist of the following: (1) $0.35375 per Series A Preferred Unit per quarter, (2) $0.09125 per Series A Preferred Unit per quarter (the "Common Unit Distribution Amount"), payable solely in common units, and (3) $0.09125 per Series A Preferred Unit per quarter (the "PIK Distribution Additional Amount"), payable solely in common units. The total number of common units payable in connection with the Common Unit Distribution Amount or the PIK Distribution Additional Amount cannot exceed $2 million in any period of 20 consecutive fiscal quarters.

Upon the Partnership's breach of certain covenants (a "Covenant Default"), the holders of the Series A Preferred Units will be entitled to an increase of $0.1825 per quarterly distribution, payable solely in common units (the "Covenant Default Additional Amount"). All accumulated and unpaid distributions will accrue interest (i) at a rate of 2.432% per quarter, or (ii) if the Partnership has failed to pay all PIK Distribution Additional Amounts or Covenant Default Additional Amounts or any Covenant Default has occurred and is continuing, at a rate of 3.429% per quarter while such failure to pay or such Covenant Default continues.

The Series A Preferred Units are convertible, at the holder's option, into common units, provided that the holder must request conversion of at least 375,000 Series A Preferred Units. The conversion price will initially be $18.30, subject to adjustment for customary events (such as unit splits). The number of common units issuable is equal to the issue price of the Series A Preferred Units (i.e. $18.30) being converted plus all accrued but unpaid distributions and accrued but unpaid interest thereon (the "Redeemable Face Amount"), divided by the applicable conversion price.

Commencing on September 2, 2014, if at any time the volume-weighted average trading price of the common units over the trailing 20-trading day period (the "VWAP Price") is less than the then-applicable conversion price, the conversion ratio will be increased to: the quotient of (1) the Redeemable Face Amount on the date that the holder's conversion notice is delivered, divided by (2) the product of (x) the VWAP Price set forth in the applicable conversion notice and (y) 91%, but will not be less than $10.

Also commencing on September 2, 2014, the Partnership will have the right at any time to convert all or part of the Series A Preferred Units into common units, if (1) the daily volume-weighted average trading price of the common units is greater than 150% of the then-applicable conversion price for 20 out of the trailing 30 trading days, and (2) certain minimum public float and trading volume requirements are satisfied.

In the event of a change of control, the Partnership will be required to make an offer to the holders of the Series A Preferred Units to purchase their Series A Preferred Units for an amount equal to 101% of their Series A Liquidation Value. In addition, in the event of certain business combinations or other transactions involving the Partnership in which the holders of common units receive cash consideration exclusively in exchange for their common units (a "Cash Event"), the Partnership must use commercially reasonable efforts to ensure that the holders of the Series A Preferred Units will be entitled to receive a security issued by the surviving entity in the Cash Event with comparable powers, preferences and rights to the Series A Preferred Units. If the Partnership is unable to ensure that the holders of the Series A Preferred Units will be entitled to receive such a security, then the Partnership will be required to make an offer to the holders of the Series A Preferred Units to purchase their Series A Preferred Units for an amount equal to 120% of their Series A Liquidation Value. If the Partnership enters into any recapitalization, reorganization, consolidation, merger, spin-off that is not a Cash Event, the Partnership will make appropriate provisions to ensure that the holders of the Series A Preferred Units receive a security with comparable powers, preferences and rights to the Series A Preferred Units upon consummation of such transaction. Subsequent to the ETE Acquisition, no unitholder exercised this option.

As of December 31, 2013, the Series A Preferred Units were convertible to 2,050,854 common units.

The following table provides a reconciliation of the beginning and ending balances of the Series A Preferred Units for the year ended December 31, 2013 and 2012:

	Units	Amount
Balance at January 1, 2012	4,371,586	$ 71
Accretion to redemption value	N/A	2
Balance at December 31, 2012	4,371,586	73
Series A Preferred Units converted into common units	(2,459,017)	(41)
Balance at December 31, 2013	1,912,569	$ 32 *

* This amount will be accreted to $35 million plus any accrued but unpaid distributions and interest by deducting amounts from partners' capital over the remaining periods until the mandatory redemption date of September 2, 2029. Accretion during 2013 was immaterial.

14. Related Party Transactions

As of December 31, 2013 and 2012, details of the Partnership’s related party receivables and related party payables were as follows:

	December 31,	
	2013	2012
Related party receivables		
HPC	$ 1	$ 1
ETE and its subsidiaries	25	5
Ranch JV	2	2
Total related party receivables	$ 28	$ 8
Related party payables		
HPC	$ 1	$ 1
ETE and its subsidiaries	68	94
Total related party payables	$ 69	$ 95

Transactions with ETE and its subsidiaries. Under the service agreement with Services Co., the Partnership paid Services Co.’s direct expenses for services performed, plus an annual fee of $10 million, and received the benefit of any cost savings recognized for these services. The services agreement has a five year term ending May 26, 2015, subject to earlier termination rights in the event of a change in control, the failure to achieve certain cost savings for the Partnership or upon an event of default. On April 30, 2013, this agreement was amended to provide for a waiver of the $10 million annual fee effective as of May 1, 2013 through and including April 30, 2015 and to clarify the scope and expenses chargeable as direct expenses thereunder.

On April 30, 2013, the Partnership entered into the second amendment (the “Operation and Service Amendment”) to the Operation and Service Agreement (the “Operation and Service Agreement”), by and among the Partnership, ETC, the General Partner and RGS. Under the Operation and Service Agreement, ETC performs certain operations, maintenance and related services reasonably required to operate and maintain certain facilities owned by the Partnership, and the Partnership reimburses ETC for actual costs and expenses incurred in connection with the provision of these services based on an annual budget agreed upon by both parties. The Operation and Service Agreement Amendment describes the services that ETC will provide in the future.

The Partnership incurred total service fees related to the agreements described above from ETE and its subsidiaries of $11 million for the year ended December 31, 2013, and $17 million for the years ended December 31, 2012 and 2011.

In conjunction with distributions made by the Partnership to the limited and general partner interests, ETE received cash distributions of $63 million, $62 million and $57 million for the years ended December 31, 2013, 2012 and 2011, respectively.

The General Partner has the right, but not the obligation, to contribute a proportionate amount of capital to the Partnership to maintain its general partner interest. No capital contributions were contributed during the years ended December 31, 2013 and 2012, respectively.

In September 2011, the Partnership purchased a 0.1% interest in MEP from ETP for $1 million in cash.

The Partnership’s Gathering and Processing segment, in the ordinary course of business, sells natural gas and NGLs to subsidiaries of ETE and records the revenue in gas sales and NGL sales. The Partnership’s Contract Services segment provides contract compression services to ETP and records revenue in gathering, transportation and other fees on the statement of operations. The Partnership’s Contract Services segment did not sell compression equipment to a subsidiary of ETP for the year ended December 31, 2013, and sold $1 million for the year ended December 31, 2012. As these transactions are between entities under common control, partners’ capital was increased, which represented a deemed contribution of the excess sales price over the carrying amounts. The Partnership’s Contract Services segment purchased compression equipment from a subsidiary of ETP for $95 million and $29 million during the years ended December 31, 2013 and 2012, respectively.

Prior to April 30, 2013, Southern Union provided certain administrative services for SUGS that were either based on SUGS's pro-rata share of combined net investment, margin and certain expenses or direct costs incurred by Southern Union on the behalf of SUGS. Southern Union also charged a management and royalty fee to SUGS for certain management support services provided by Southern Union on the behalf of SUGS and for the use of certain Southern Union trademarks, trade names and service marks by SUGS. The amounts were $21 million and $1 million for the period from March 26, 2012 to December 31, 2012. These administrative services were no longer being provided subsequent to the SUGS Acquisition.

Transactions with HPC. Under a Master Services Agreement with HPC, the Partnership operates and provides all employees and services for the operation and management of HPC. For the years ended December 31, 2013, 2012, and 2011, the related party general and administrative expenses reimbursed to the Partnership were $18 million, $20 million, and $17 million, respectively, which is recorded in gathering, transportation and other fees on the statements of operations.

The Partnership's Contract Services segment provides compression services to HPC and records revenue in gathering, transportation and other fees on the statement of operations. The Partnership also receives transportation services from HPC and records the cost as cost of sales.

Transactions with Lone Star. In 2013, the Partnership entered into a nineteen month agreement to sell NGL to Lone Star for approximately $5 million per month. For the year ended December 31, 2013, the Partnership had recorded $26 million in NGL sales under this contract.

Transactions with EPD and its subsidiaries. In January 2012, EPD sold a significant portion of its ownership in ETE's common units, and subsequent to that transaction, owns less than 5% of ETE's outstanding common units. As such, EPD is no longer considered a related party. During 2011, EPD owned a portion of ETE's outstanding common units and therefore was considered a related party along with any of its subsidiaries. The Partnership, in the ordinary course of business, sells natural gas and NGLs to subsidiaries of EPD and records the revenue in gas sales and NGL sales. The Partnership also incurs NGL processing fees and transportation fees with subsidiaries of EPD and records these fees as cost of sales.

15. Concentration Risk

The following table provides information about the extent of reliance on major customers and gas suppliers. Total revenues and cost of sales from transactions with an external customer or supplier amounting to 10% or more of revenue or cost of gas and liquids are disclosed below, together with the identity of the reporting segment.

		Years Ended December 31,		
	Reportable Segment	2013	2012	2011
Customer				
Customer A	Gathering and Processing	$ 381	$ 367	$ 366
Customer B	Gathering and Processing	362	451	—
Supplier				
Supplier A	Gathering and Processing	164	171	133
Supplier B	Gathering and Processing	185	—	—

The Partnership is a party to various commercial netting agreements that allow it and contractual counterparties to net receivable and payable obligations. These agreements are customary and the terms follow standard industry practice. In the opinion of management, these agreements reduce the overall counterparty risk exposure.

16. Segment Information

The Partnership has five reportable segments: Gathering and Processing, Natural Gas Transportation, NGL Services, Contract Services, and Corporate. The reportable segments are as described below:

Gathering and Processing. The Partnership provides "wellhead-to-market" services to producers of natural gas, which include transporting raw natural gas from the wellhead through gathering systems, processing raw natural gas to separate NGLs from the raw natural gas and selling or delivering pipeline-quality natural gas and NGLs to various markets and pipeline systems. This segment also includes ELG and the Partnership's 33.33% membership interest in Ranch JV, which processes natural gas delivered from the NGLs-rich Bone Spring and Avalon shale formations in west Texas. The Partnership completed the SUGS Acquisition on April 30, 2013 which was a reorganization of entities under common control. Therefore, the Gathering and Processing segment amounts have been retrospectively adjusted to reflect the SUGS Acquisition beginning March 26, 2012, the date upon which common control began.

Natural Gas Transportation. The Partnership owns a 49.99% general partner interest in HPC, which owns RIGS, a 450-mile intrastate pipeline that delivers natural gas from northwest Louisiana to downstream pipelines and markets, a 50% membership interest in MEP, which owns a 500-mile interstate natural gas pipeline stretching from southeast Oklahoma through northeast Texas, northern Louisiana and central Mississippi to an interconnect with the Transcontinental Gas Pipe Line system in Butler, Alabama. This segment also includes Gulf States, which owns a 10-mile interstate pipeline that extends from Harrison County, Texas to Caddo Parish, Louisiana.

NGL Services. The Partnership owns a 30% membership interest in Lone Star, an entity owning a diverse set of midstream energy assets including pipelines, storage, fractionation and processing facilities located in the states of Texas, New Mexico, Mississippi and Louisiana.

Contract Services. The Partnership owns and operates a fleet of compressors used to provide turn-key natural gas compression services for customer specific systems. The Partnership also owns and operates a fleet of equipment used to provide treating services, such as carbon dioxide and hydrogen sulfide removal, natural gas cooling, dehydration and BTU management.

Corporate. The Corporate segment comprises the Partnership’s corporate assets.

The Partnership accounts for intersegment revenues as if the revenues were to third parties, exclusive of certain cost of capital charges.

Management evaluates the performance of each segment and makes capital allocation decisions through the separate consideration of segment margin and operation and maintenance expenses. Segment margin, for the Gathering and Processing and the Natural Gas Transportation segments is defined as total revenues, including service fees, less cost of sales. In the Contract Services segment, segment margin is defined as revenues less direct costs.

Management believes segment margin is an important measure because it directly relates to volume, commodity price changes, revenue generating horsepower and revenue generating gallons per minute. Operation and maintenance expenses are a separate measure used by management to evaluate performance of field operations. Direct labor, insurance, property taxes, repair and maintenance, utilities and contract services comprise the most significant portion of operation and maintenance expenses. These expenses fluctuate depending on the activities performed during a specific period. The Partnership does not deduct operation and maintenance expenses from total revenues in calculating segment margin because management separately evaluates commodity volume and price changes in segment margin. The Partnership does not record segment margin for its investments in unconsolidated affiliates (HPC, MEP, Lone Star, Ranch JV, and Grey Ranch) because it records its ownership percentages of their net income as income from unconsolidated affiliates in accordance with the equity method of accounting.

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Results for each period, together with amounts related to each segment are shown below:

	Years Ended December 31, 2013	2012	2011
External Revenue			
Gathering and Processing	$ 2,287	$ 1,797	$ 1,226
Natural Gas Transportation	1	1	1
NGL Services	—	—	—
Contract Services	215	183	190
Corporate	18	19	17
Eliminations	—	—	—
Total	$ 2,521	$ 2,000	$ 1,434
Intersegment Revenue			
Gathering and Processing	$ —	$ —	$ —
Natural Gas Transportation	—	—	—
NGL Services	—	—	—
Contract Services	15	21	17
Corporate	—	—	—
Eliminations	(15)	(21)	(17)
Total	$ —	$ —	$ —
Cost of Sales			
Gathering and Processing	$ 1,767	$ 1,373	$ 993
Natural Gas Transportation	—	(1)	(2)
NGL Services	—	—	—
Contract Services	26	15	22
Corporate	—	—	—
Eliminations	—	—	—
Total	$ 1,793	$ 1,387	$ 1,013
Segment Margin			
Gathering and Processing	$ 521	$ 423	$ 233
Natural Gas Transportation	—	2	3
NGL Services	—	—	—
Contract Services	204	189	185
Corporate	18	20	17
Eliminations	(15)	(21)	(17)
Total	$ 728	$ 613	$ 421
Operation and Maintenance			
Gathering and Processing	$ 237	$ 183	$ 98
Natural Gas Transportation	—	—	—
NGL Services	—	—	—
Contract Services	72	66	66
Corporate	1	—	—
Eliminations	(14)	(21)	(17)
Total	$ 296	$ 228	$ 147
Depreciation and Amortization			
Gathering and Processing	$ 186	$ 159	$ 87
Natural Gas Transportation	—	—	—
NGL Services	—	—	—
Contract Services	98	86	78
Corporate	3	7	4
Eliminations	—	—	—
Total	$ 287	$ 252	$ 169

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	Years Ended December 31,		
	2013	2012	2011
Income from Unconsolidated Affiliates			
Gathering and Processing	$ 1	$ (10)	$ —
Natural Gas Transportation	70	71	92
NGL Services	64	44	28
Contract Services	—	—	—
Corporate	—	—	—
Eliminations	—	—	—
Total	$ 135	$ 105	$ 120
Expenditures for Long-Lived Assets			
Gathering and Processing	$ 721	$ 395	$ 282
Natural Gas Transportation	—	—	—
NGL Services	—	—	—
Contract Services	311	164	120
Corporate	2	1	4
Eliminations	—	—	—
Total	$ 1,034	$ 560	$ 406

	December 31, 2013		
	2013	2012	2011
Assets			
Gathering and Processing	$ 4,748	$ 4,210	$ 1,960
Natural Gas Transportation	991	1,232	1,297
NGL Services	1,070	948	629
Contract Services	1,897	1,672	1,621
Corporate	76	61	61
Eliminations	—	—	—
Total	$ 8,782	$ 8,123	$ 5,568
Investment in Unconsolidated Affiliates			
Gathering and Processing	$ 36	$ 35	$ —
Natural Gas Transportation	991	1,231	1,296
NGL Services	1,070	948	629
Contract Services	—	—	—
Corporate	—	—	—
Eliminations	—	—	—
Total	$ 2,097	$ 2,214	$ 1,925
Goodwill			
Gathering and Processing	$ 651	$ 651	$ 313
Natural Gas Transportation	—	—	—
NGL Services	—	—	—
Contract Services	477	477	477
Corporate	—	—	—
Eliminations	—	—	—
Total	$ 1,128	$ 1,128	$ 790

The table below provides a reconciliation of total segment margin to income before income taxes:

	Years Ended December 31,		
	2013	2012	2011
Total segment margin	$ 728	$ 613	$ 421
Operation and maintenance	(296)	(228)	(147)
General and administrative	(88)	(100)	(67)
(Loss) gain on assets sales, net	(2)	(3)	2
Depreciation and amortization	(287)	(252)	(169)
Income from unconsolidated affiliates	135	105	120
Interest expense, net	(164)	(122)	(103)
Loss on debt refinancing, net	(7)	(8)	—
Other income and deductions, net	7	29 *	17
Income before income taxes	$ 26	$ 34	$ 74

* Other income and deductions, net for the year ended December 31, 2012, included a one-time producer payment of $16 million related to an assignment of certain contracts.

17. Equity-Based Compensation

In December 2011, the Partnership's unitholders approved the Regency Energy Partners LP 2011 Long-Term Incentive Plan (the "2011 Incentive Plan"), which provides for awards of options to purchase the Partnership's common units; awards of the Partnership's restricted units, phantom units and common units; awards of distribution equivalent rights; awards of common unit appreciation rights; and other unit-based awards to employees, directors and consultants of the Partnership and its affiliates and subsidiaries. The 2011 Incentive Plan will be administered by the Compensation Committee of the board of directors, which may, in its sole discretion, delegate its powers and duties under the 2011 Incentive Plan to the Chief Executive Officer. Up to 3,000,000 of the Partnership's common units may be granted as awards under the 2011 Incentive Plan, with such amount subject to adjustment as provided for under the terms of the 2011 Incentive Plan.

The 2011 Incentive Plan may be amended or terminated at any time by the board of directors or the Compensation Committee without the consent of any participant or unitholder, including an amendment to increase the number of common units available for awards under the plan; however, any material amendment, such as a change in the types of awards available under the plan, would require the approval of the unitholders of the Partnership. The Compensation Committee is also authorized to make adjustments in the terms and conditions of, and the criteria included in awards under the 2011 Incentive Plan in specified circumstances. The 2011 Incentive Plan is effective until December 19, 2021 or, if earlier, the time at which all available units under the 2011 Incentive Plan have been issued to participants or the time of termination of the plan by the board of directors.

Unit-based compensation expense of $7 million, $5 million, and $3 million is recorded in general and administrative expense in the statement of operations for the years ended December 31, 2013, 2012 and 2011, respectively.

Common Unit Options. The fair value of each option award is estimated on the date of grant using the Black-Scholes Option Pricing Model. Upon the exercise of the common unit options, the Partnership intends to settle these obligations with new issues of common units on a net basis. The common unit options activity for the years ended December 31, 2013, 2012, and 2011 is as follows:

2013

Common Unit Options	Units	Weighted Average Exercise Price
Outstanding at the beginning of period	156,550	$ 21.96
Exercised	(14,000)	21.14
Outstanding at end of period	142,550	22.04
Exercisable at the end of the period	142,550	

2012

Common Unit Options	Units	Weighted Average Exercise Price
Outstanding at the beginning of period	156,850	$ 21.99
Forfeited or expired	(300)	23.73
Outstanding at end of period	156,550	21.96
Exercisable at the end of the period	156,550	

2011

Common Unit Options	Units	Weighted Average Exercise Price
Outstanding at the beginning of period	201,950	$ 21.93
Exercised	(38,300)	20.84
Forfeited or expired	(6,800)	26.72
Outstanding at end of period	156,850	21.99
Exercisable at the end of the period	156,850	

The common unit options have an intrinsic value of less than $1 million related to non-vested units with a weighted average contractual term of 2.4 years. Intrinsic value is the closing market price of a unit less the option strike price, multiplied by the number of unit options outstanding as of the end of the period presented. Unit options with an exercise price greater than the end of the period closing market price are excluded.

Phantom Units. In January 2014, the Partnership awarded 668,074 phantom units to senior management and certain key employees. These awards are service condition (time-based) grants that vest 60% at the end of the third year of service and 40% at the end of the fifth year of service.

During 2013, the Partnership awarded 62,360 phantom units to senior management and certain key employees. These awards are service condition (time-based) grants that generally vest 60% at the end of the third year of service and 40% at the end of the fifth year of service. Distributions on the phantom units will be paid concurrent with the Partnership's distribution for common units.

In December 2012, the Partnership awarded 495,375 phantom units to senior management and certain key employees. These awards are service condition (time-based) grants that vest 60% at the end of the third year of service and 40% at the end of the fifth year of service. Also during 2012, 8,250 phantom units were awarded to senior management and key employees as service condition (time-based) grants that generally vest ratably over the next 5 years. Distributions on the phantom units (including non-vested units) will be paid concurrent with the Partnership's distribution for common units.

During 2011, the Partnership awarded 596,320 phantom units to senior management and certain key employees. These awards are service condition (time-based) grants that generally vest ratably over the next 5 years. Distributions on the phantom units (including non-vested units) will be paid concurrent with the Partnership's distribution for common units.

The following table presents phantom unit activity for the years ended December 31, 2013, 2012 and 2011:

2013

Phantom Units	Units	Weighted Average Grant Date Fair Value
Outstanding at the beginning of the period	1,231,342	$ 23.22
Service condition grants	62,360	25.44
Vested service condition	(231,163)	24.80
Forfeited service condition	(35,900)	23.22
Forfeited market condition	(44,397)	19.52
Total outstanding at end of period	982,242	23.16

2012

Phantom Units	Units	Weighted Average Grant Date Fair Value
Outstanding at the beginning of the period	1,086,393	$ 24.51
Service condition grants	503,625	21.39
Vested service condition	(223,258)	24.71
Vested market condition	(10,200)	19.52
Forfeited service condition	(120,868)	24.85
Forfeited market condition	(4,350)	19.52
Total outstanding at end of period	1,231,342	23.22

2011

Phantom Units	Units	Weighted Average Grant Date Fair Value
Outstanding at the beginning of the period	742,517	$ 23.61
Service condition grants	596,320	24.55
Vested service condition	(142,520)	24.73
Vested market condition	(8,550)	19.52
Forfeited service condition	(88,474)	24.99
Forfeited market condition	(12,900)	19.52
Total outstanding at end of period	1,086,393	24.51

The Partnership expects to recognize $19 million of unit-based compensation expense related to non-vested phantom units over a period of 3.3 years.

18. Quarterly Financial Data (Unaudited)

2013	Quarter Ended December 31	Quarter Ended September 30	Quarter Ended June 30	Quarter Ended March 31
Operating revenues	$ 677	$ 665	$ 639	$ 540
Operating income (loss)	12	24	34	(15)
Net (loss) income attributable to Regency Energy Partners LP	(1)	39	10	(29)
Earnings per common units:				
Basic net (loss) income per common unit	(0.03)	0.16	0.07	(0.06)
Diluted net (loss) income per common unit	(0.03)	0.05	0.07	(0.06)

2012 *	Quarter Ended December 31	Quarter Ended September 30	Quarter Ended June 30	Quarter Ended March 31
Operating revenues	$ 587	$ 527	$ 511	$ 375
Operating income (loss)	8	5	22	(5)
Net (loss) income attributable to Regency Energy Partners LP	(8)	(1)	26	15
Earnings per common units:				
Basic net (loss) income per common unit	(0.08)	(0.04)	0.14	0.15
Diluted net (loss) income per common unit	(0.08)	(0.04)	0.10	0.14

* Due to the SUGS Acquisition, these quarterly results have been retrospectively adjusted to include the operations of SUGS beginning March 26, 2012, the date upon which common control began.

5. REGENCY GP LP AND SUBSIDIARIES CONSOLIDATED FINANCIAL STATEMENTS

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Partners
Regency GP LP

We have audited the accompanying consolidated balance sheets of Regency GP LP (a Delaware limited partnership) and subsidiaries (the "Partnership") as of December 31, 2013 and 2012, and the related consolidated statements of operations, comprehensive income, cash flows, and partners' capital and noncontrolling interest for each of the three years in the period ended December 31, 2013. 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 financial statements of Midcontinent Express Pipeline LLC, a 50 percent owned investee company, the Partnership's investment in which is accounted for under the equity method of accounting. The Partnership's investment in Midcontinent Express Pipeline LLC as of December 31, 2013 and 2012 was $548 million and $581 million, respectively, and its equity in the earnings of Midcontinent Express Pipeline LLC was $39 million, $42 million, and $43 million, respectively, for each of the three years in the period ended December 31, 2013. Those statements were audited by other auditors, whose reports has been furnished to us, and our opinion, insofar as it relates to the amounts included for Midcontinent Express Pipeline LLC, is based solely on the reports 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. We were not engaged to perform an audit of the Partnership's internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Partnership's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, 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 reports of the other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audits and the reports of the other auditors, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Regency GP LP and subsidiaries as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1, the accompanying consolidated financial statements have been adjusted to reflect the acquisition of an entity under common control, which has been accounted for in a manner similar to a pooling of interests.

/s/ GRANT THORNTON LLP

Dallas, Texas
February 27, 2014

Regency GP LP

Consolidated Balance Sheets
(in millions)

	December 31, 2013	December 31, 2012
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 19	$ 53
Trade accounts receivable	292	222
Related party receivables	28	8
Inventories	42	27
Other current assets	19	30
Total current assets	400	340
Property, Plant and Equipment:		
Gathering and transmission systems	1,671	1,308
Compression equipment	1,627	1,326
Gas plants and buildings	825	568
Other property, plant and equipment	414	377
Construction-in-progress	513	507
Total property, plant and equipment	5,050	4,086
Less accumulated depreciation	(632)	(400)
Property, plant and equipment, net	4,418	3,686
Other Assets:		
Investments in unconsolidated affiliates	2,097	2,214
Other, net of accumulated amortization of debt issuance costs of $24 and $17	57	43
Total other assets	2,154	2,257
Intangible Assets and Goodwill:		
Intangible assets, net of accumulated amortization of $107 and $77	682	712
Goodwill	1,128	1,128
Total intangible assets and goodwill	1,810	1,840
TOTAL ASSETS	$ 8,782	$ 8,123
LIABILITIES & PARTNERS' CAPITAL AND NONCONTROLLING INTEREST		
Current Liabilities:		
Drafts payable	$ 26	$ 10
Trade accounts payable	291	255
Related party payables	69	95
Accrued interest	38	30
Other current liabilities	51	99
Total current liabilities	475	489
Long-term derivative liabilities	19	25
Other long-term liabilities	30	39
Long-term debt, net	3,310	2,157
Commitments and contingencies		
Regency's Series A Preferred Units, redemption amount of $38 and $85	32	73
Partners' Capital and Noncontrolling Interest:		
Partners' capital	782	326
Predecessor equity	—	1,733
Total partners' capital	782	2,059
Noncontrolling interest	4,134	3,281
Total partners' capital and noncontrolling interest	4,916	5,340
TOTAL LIABILITIES AND PARTNERS' CAPITAL AND NONCONTROLLING INTEREST	$ 8,782	$ 8,123

See accompanying notes to consolidated financial statements

Regency GP LP

Consolidated Statements of Operations
(in millions)

	Years Ended December 31,		
	2013	2012	2011
REVENUES			
Gas sales, including related party amounts of $71, $42, and $23	$ 826	$ 508	$ 456
NGL sales, including related party amounts of $81, $28, and $365	1,053	991	603
Gathering, transportation and other fees, including related party amounts of $26, $29, and $24	545	401	351
Net realized and unrealized (loss) gain from derivatives	(8)	23	(19)
Other, including related party amounts of $-, $1, and $10	105	77	43
Total revenues	2,521	2,000	1,434
OPERATING COSTS AND EXPENSES			
Cost of sales, including related party amounts of $56, $35, and $22	1,793	1,387	1,013
Operation and maintenance	296	228	147
General and administrative, including related party amounts of $11, $15, and $17	88	100	67
Loss (gain) on asset sales, net	2	3	(2)
Depreciation and amortization	287	252	169
Total operating costs and expenses	2,466	1,970	1,394
OPERATING INCOME	55	30	40
Income from unconsolidated affiliates	135	105	120
Interest expense, net	(164)	(122)	(103)
Loss on debt refinancing, net	(7)	(8)	—
Other income and deductions, net	7	29	17
INCOME BEFORE INCOME TAXES	26	34	74
Income tax benefit	(1)	—	—
NET INCOME	$ 27	$ 34	$ 74
Net income attributable to noncontrolling interest	(16)	(25)	(67)
NET INCOME ATTRIBUTABLE TO REGENCY GP LP	$ 11	$ 9	$ 7

See accompanying notes to consolidated financial statements

Regency GP LP

Consolidated Statements of Comprehensive Income
(in millions)

	Years Ended December 31,		
	2013	2012	2011
Net income	$ 27	$ 34	$ 74
Other comprehensive income:			
Net cash flow hedge amounts reclassified to earnings	—	6	19
Change in fair value of cash flow hedges	—	(4)	(13)
Total other comprehensive income	$ —	$ 2	$ 6
Comprehensive income	$ 27	$ 36	$ 80
Comprehensive income attributable to noncontrolling interest	16	25	67
Comprehensive income attributable to Regency GP LP	$ 11	$ 11	$ 13

See accompanying notes to consolidated financial statements

Regency GP LP

Consolidated Statements of Partners' Capital and Noncontrolling Interest
(in millions)

	Partners' Interest	AOCI	Predecessor Equity	Noncontrolling Interest	Total
Balance—December 31, 2010	$ 333	$ (11)	$ —	$ 2,972	$ 3,294
Regency common unit offerings, net of costs	—	—	—	436	436
Regency unit-based compensation expenses	—	—	—	3	3
Distributions to partners and noncontrolling interests	(10)	—	—	(264)	(274)
Net income	7	—	—	67	74
Distributions to Regency Series A Preferred Units	—	—	—	(8)	(8)
Net cash flow hedge amounts reclassified to earnings	—	19	—	—	19
Net change in fair value of cash flow hedges	—	(13)	—	—	(13)
Balance—December 31, 2011	$ 330	$ (5)	$ —	$ 3,206	$ 3,531
Regency common unit offerings, net of costs	—	—	—	312	312
Regency common units issued under LTIP, net of forfeitures and tax withholding	—	—	—	(1)	(1)
Regency unit-based compensation expenses	—	—	—	5	5
Distributions to partners and noncontrolling interests	(13)	—	—	(309)	(322)
Net income	9	—	(14)	39	34
Contributions from noncontrolling interest	—	—	—	42	42
Distributions to Regency Series A Preferred Units	—	—	—	(8)	(8)
Accretion of Series A Preferred Units	—	—	—	(2)	(2)
Net cash flow hedge amounts reclassified to earnings	—	5	—	—	5
Contribution of net investment to unitholders	—	(3)	1,747	—	1,744
Balance—December 31, 2012	$ 326	$ (3)	$ 1,733	$ 3,284	$ 5,340
Contribution of net investment to Regency	1,925	3	(1,928)	—	—
Regency issuance of common units in connection with the SUGS Acquisition, net of costs	(819)	—	—	819	—
Regency issuance of Regency Class F common units in connection with the SUGS Acquisition, net of costs	(142)	—	—	142	—
Contribution of assets between entities under common control below historical cost	(504)	—	231	—	(273)
Regency common unit offerings, net of costs	—	—	—	149	149
Conversion of Regency Series A Preferred Units for common units	—	—	—	41	41
Regency unit-based compensation expenses	—	—	—	7	7
Distributions to partners, noncontrolling interests and subsidiary's unvested unit awards	(15)	—	—	(371)	(386)
Contributions from noncontrolling interest	—	—	—	17	17
Net income	11	—	(36)	52	27
Distributions to Regency Series A Preferred Units	—	—	—	(6)	(6)
Balance—December 31, 2013	$ 782	$ —	$ —	$ 4,134	$ 4,916

See accompanying notes to consolidated financial statements

Regency GP LP

Consolidated Statements of Cash Flows
(in millions)

	Years Ended December 31, 2013	2012	2011
OPERATING ACTIVITIES			
Net income	$ 27	$ 34	$ 74
Reconciliation of net income to net cash flows provided by operating activities:			
Depreciation and amortization, including debt issuance cost amortization and bond premium write-off and amortization	293	259	175
Income from unconsolidated affiliates	(135)	(105)	(120)
Derivative valuation changes	6	(12)	(21)
Loss (gain) on asset sales, net	2	3	(2)
Regency unit-based compensation expenses	7	5	3
Cash flow changes in current assets and liabilities:			
Trade accounts receivable and related party receivables	(96)	—	(8)
Other current assets and other current liabilities	(54)	10	11
Trade accounts payable, related party payables and deferred revenues	119	18	23
Distributions of earnings received from unconsolidated affiliates	142	121	119
Cash flow changes in other assets and liabilities	125	(9)	—
Net cash flows provided by operating activities	436	324	254
INVESTING ACTIVITIES			
Capital expenditures	(1,034)	(560)	(406)
Capital contributions to unconsolidated affiliates	(148)	(356)	(53)
Distributions in excess of earnings of unconsolidated affiliates	249	83	74
Acquisition of investment in unconsolidated affiliates, net of cash received	—	—	(594)
Acquisitions, net of cash received	(475)	—	—
Proceeds from asset sales	15	26	24
Net cash flows used in investing activities	(1,393)	(807)	(955)
FINANCING ACTIVITIES			
Borrowings (repayments) under revolving credit facility, net	318	(140)	47
Proceeds from issuance of senior notes	1,000	700	500
Redemptions of senior notes	(163)	(88)	—
Debt issuance costs	(24)	(15)	(10)
Distributions to non-controlling interest and subsidiary distributions on unvested unit awards	(371)	(309)	(264)
Partner distributions	(15)	(13)	(10)
Contributions from noncontrolling interest	17	42	—
Contributions from previous parent	—	51	—
Drafts payable	18	4	2
Subsidiary common units issued under LTIP, net of forfeitures and tax withholding	—	(1)	—
Proceeds from Regency issuance of common units, net of issuance costs	149	312	436
Distributions to Regency Series A Preferred Units	(6)	(8)	(8)
Net cash flows provided by financing activities	923	535	693
Net change in cash and cash equivalents	(34)	52	(8)
Cash and cash equivalents at beginning of period	53	1	9
Cash and cash equivalents at end of period	$ 19	$ 53	$ 1
Supplemental cash flow information:			
Accrued capital expenditures	$ 60	$ 136	$ 24
Issuance of Class F and common units in connection with SUGS Acquisition	961	—	—
Interest paid, net of amounts capitalized	146	112	83
Income taxes paid	—	—	2
Accrued capital contribution to unconsolidated affiliate	13	23	—

See accompanying notes to consolidated financial statements

Regency GP LP
Notes to Consolidated Financial Statements
(Tabular dollar amounts are in millions)

1. Organization and Basis of Presentation

Organization of Regency GP LP. Regency GP LP (the "General Partner") is the general partner of Regency Energy Partners LP. The General Partner owns a 1.3% general partner interest and the incentive distribution rights of Regency Energy Partners LP. Regency GP LLC owns a 0.001% general partner interest in the General Partner and the remaining limited partner interest is owned by ETE GP Acquirer LLC, which is a wholly-owned subsidiary of Energy Transfer Equity, L.P. ("ETE").

Organization of Regency Energy Partners LP. Regency Energy Partners LP and its subsidiaries ("Regency" or the "Partnership") are engaged in the business of gathering, processing and transporting natural gas and natural gas liquids ("NGLs") as well as providing contract compression services.

SUGS Acquisition. In April 2013, the Partnership acquired Southern Union Gas Services ("SUGS") from Southern Union Company ("Southern Union"), a wholly-owned subsidiary of Holdco, for $1.5 billion (the "SUGS Acquisition"). The Partnership financed the acquisition by issuing to Southern Union 31,372,419 of Regency common units and 6,274,483 Regency Class F common units. The Regency Class F common units are not entitled to participate in the Partnership's distributions for twenty-four months post-transaction closing. The remaining $600 million, less $107 million of closing adjustments, was paid in cash. In addition, ETE agreed to forgo IDR payments on the Partnership common units issued with this transaction for the twenty-four months post-transaction closing and to suspend the $10 million annual management fee paid by the Partnership for two years post-transaction close.

The Regency common units and Regency Class F common units related to the SUGS Acquisition were issued in a private placement conducted in accordance with the exemption from registration requirements of the Securities Act of 1933, as amended under Section 4(2) thereof. The Regency Class F common units will convert into common units on a one-for-one basis in May 2015.

The cash portion of the SUGS Acquisition was funded from the net proceeds of $600 million of senior notes issued by the Partnership on April 30, 2013 in a private placement. In December 2013, these senior notes were exchanged for senior notes that are substantially identical, except that the exchange senior notes are registered under federal securities law and do not have any transfer restrictions. In January 2014, Panhandle Eastern Pipe Line Company, LP ("PEPL") entered into an agreement and plan of merger with Southern Union and PEPL Holdings, LLC ("PEPL Holdings"), pursuant to which each of Southern Union and PEPL Holdings were merged with and into PEPL, with PEPL as the surviving entity. In connection with this merger, PEPL assumed the guarantee of collection with respect to the payment of the principal amounts of the senior notes issued.

The Partnership accounted for the SUGS Acquisition in a manner similar to the pooling of interest method of accounting, as it was a transaction between commonly controlled entities. Under this method of accounting, the Partnership reflected historical balance sheet data for the Partnership and SUGS instead of reflecting the fair market value of SUGS assets and liabilities from the date of acquisition forward. The Partnership retrospectively adjusted its financial statements to include the balances and operations of SUGS from March 26, 2012 (the date upon which common control began).

The assets acquired and liabilities assumed in the SUGS Acquisition were as follows:

		April 30, 2013
Current assets	$	113
Property, plant and equipment, net		1,608
Goodwill		337
Other non-current assets		1
Total assets acquired	$	2,059
Less:		
Current liabilities		(93)
Non-current liabilities		(36)
Net assets acquired	$	1,930

The following table presents the revenues and net income for the previously separate entities and combined amounts presented herein:

	Years Ended December 31,	
	2013	2012
Revenues:		
Partnership	$ 2,253	$ 1,339
SUGS (1)	268	661
Combined	$ 2,521	$ 2,000
Net income (loss):		
Partnership	$ 63	$ 48
SUGS (1)	(36)	(14)
Combined	$ 27	$ 34

(1) Combined amounts attributable to SUGS include the period from March 26, 2012 to December 31, 2012 for the year ended December 31, 2012, and the period from January 1, 2013 to April 30, 2013 for the year ended December 31, 2013. Subsequent to the closing of the SUGS Acquisition on April 30, 2013, the results of SUGS were attributable to the Partnership.

Basis of presentation. The consolidated financial statements of the General Partner have been prepared in accordance with GAAP and include the accounts of all controlled subsidiaries after the elimination of all intercompany accounts and transactions. Certain prior year numbers have been conformed to the current year presentation. Subsequent events have been evaluated through February 27, 2014, the date the financial statements were issued.

2. Summary of Significant Accounting Policies

Use of Estimates. These consolidated financial statements have been prepared in conformity with GAAP, which includes the use of estimates and assumptions by management that affect the reported amounts of assets, liabilities, revenues, expenses and disclosure of contingent assets and liabilities that exist at the date of the financial statements. Although these estimates are based on management's available knowledge of current and expected future events, actual results could be different from those estimates.

Common Control Transactions. Entities and assets acquired from ETE and its affiliates are accounted for as common control transactions whereby the net assets acquired are combined with the Partnership's net assets at their historical amounts. If consideration transferred differs from the carrying value of the net assets acquired, the excess or deficiency is treated as a capital transaction similar to a dividend or capital contribution. To the extent that such transactions require prior periods to be recast, historical net equity amounts prior to the transaction date are reflected in predecessor equity.

Cash and Cash Equivalents. Cash and cash equivalents include temporary cash investments with original maturities of three months or less.

Equity Method Investments. The equity method of accounting is used to account for the Partnership's interest in investments of greater than 20% voting interest or where the Partnership exerts significant influence over an investee but lacks control over the investee.

Inventories. Inventories are valued at the lower of cost or market and include materials and parts primarily utilized by the Contract Services segment.

Property, Plant and Equipment. Property, plant and equipment is recorded at historical cost of construction or, upon acquisition, the fair value of the assets acquired. Gains or losses on sales or retirements of assets are included in operating income unless the disposition is treated as discontinued operations. Natural gas and NGLs used to maintain pipeline minimum pressures is and classified as property, plant and equipment. Financing costs associated with the construction of larger assets requiring ongoing efforts over a period of time are capitalized. For the years ended December 31, 2013, 2012 and 2011, the Partnership capitalized interest of $2 million, $1 million and $1 million, respectively. The costs of maintenance and repairs, which are not significant improvements, are expensed when incurred. Expenditures to extend the useful lives of the assets are capitalized.

Depreciation expense related to property, plant and equipment was $258 million, $219 million, and $138 million for the years ended December 31, 2013, 2012 and 2011, respectively. In March 2012, the Partnership recorded a $7 million "out-of-period" adjustment to depreciation expense to correct the estimated useful lives of certain assets to comply with its policy.

Depreciation of property, plant and equipment is recorded on a straight-line basis over the following estimated useful lives:

Functional Class of Property	Useful Lives (Years)
Gathering and Transmission Systems	10 - 50
Compression Equipment	2 - 30
Gas Plants and Buildings	5 - 35
Other property, plant and equipment	3 - 15

Intangible Assets. As of December 31, 2013, intangible assets consisted of trade names and customer relations, and are amortized on a straight line basis over their estimated useful lives, which is the period over which the assets are expected to contribute directly or indirectly to the Partnership's future cash flows. The estimated useful lives range from 20 to 30 years.

The Partnership assesses long-lived assets, including property, plant and equipment and intangible assets, for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability is assessed by comparing the carrying amount of an asset to undiscounted future net cash flows expected to be generated by the asset. If such assets are considered to be impaired, the impairment to be recognized is measured as the amount by which the carrying amounts exceed the fair value of the assets. The Partnership did not record any impairment in 2013, 2012 or 2011.

Goodwill. Goodwill represents the excess of the purchase price over the fair value of identifiable net assets acquired in a business combination. Goodwill is not amortized, but is tested for impairment annually based on the carrying values as of November 30 or December 31 depending on the reporting unit, or more frequently if impairment indicators arise that suggest the carrying value of goodwill may not be recovered. The Partnership has the option to first assess qualitative factors to determine whether it is more likely than not that the fair value of the reporting unit is less than its carrying amount as a basis for determining whether further impairment testing is necessary. Impairment is indicated when the carrying amount of a reporting unit exceeds its fair value. To estimate the fair value of the reporting units, the Partnership makes estimates and judgments about future cash flows, as well as revenues, cost of sales, operating expenses, capital expenditures and net working capital based on assumptions that are consistent with the Partnership's most recent forecast. At the time it is determined that an impairment has occurred, the carrying value of the goodwill is written down to its fair value. The Partnership did not record any impairment in 2013, 2012 or 2011.

Other Assets, net. Other assets, net primarily consists of debt issuance costs, which are capitalized and amortized to interest expense, net over the life of the related debt.

Gas Imbalances. Quantities of natural gas or NGLs over-delivered or under-delivered related to imbalance agreements are recorded monthly as other current assets or other current liabilities using then current market prices or the weighted average prices of natural gas or NGLs at the plant or system pursuant to imbalance agreements for which settlement prices are not contractually established. Within certain volumetric limits determined at the sole discretion of the creditor, these imbalances are generally settled by deliveries of natural gas. Imbalance receivables and payables as of December 31, 2013 and 2012 were immaterial.

Asset Retirement Obligations. Legal obligations associated with the retirement of long-lived assets are recorded at fair value at the time the obligations are incurred, if a reasonable estimate of fair value can be made. Present value techniques are used which reflect assumptions such as removal and remediation costs, inflation, and profit margins that third parties would demand to settle the amount of the future obligation. The Partnership does not include a market risk premium for unforeseeable circumstances in its fair value estimates because such a premium cannot be reliably estimated. Upon initial recognition of the liability, costs are capitalized as a part of the long-lived asset and allocated to expense over the useful life of the related asset. The liability is accreted to its present value each period with accretion being recorded to operating expense with a corresponding increase in the carrying amount of the liability. The ARO assets and liabilities were immaterial as of December 31, 2013.

Environmental. The Partnership's operations are subject to federal, state and local laws and rules and regulations regarding water quality, hazardous and solid waste management, air quality control and other environmental matters. These laws, rules and regulations require the Partnership to conduct its operations in a specified manner and to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections and other approvals. Failure to comply with applicable environmental laws, rules and regulations may expose the Partnership to significant fines, penalties and/or interruptions in operations. The Partnership's environmental policies and procedures are designed to achieve compliance with such applicable laws and regulations. These evolving laws and regulations and claims for damages to property, employees, other persons and the environment resulting from current or past operations may result in significant expenditures and liabilities in the future.

Predecessor Equity. Predecessor equity included on the consolidated statement of partners' capital and noncontrolling interest represents SUGS member's capital prior to the acquisition date (April 30, 2013).

Revenue Recognition. The Partnership earns revenue from (i) domestic sales of natural gas, NGLs and condensate, (ii) natural gas gathering, processing and transportation, and (iii) contract compression and treating services. Revenue associated with sales of natural gas, NGLs and condensate are recognized when title passes to the customer, which is when the risk of ownership passes to the purchaser and physical delivery occurs. Revenue associated with transportation and processing fees are recognized when the service is provided. For contract compression and contract treating services, revenue is recognized when the service is performed. For gathering and processing services, the Partnership receives either fees or commodities from natural gas producers depending on the type of contract. Commodities received are in turn sold and recognized as revenue in accordance with the criteria outlined above. Under the percentage-of-proceeds contract type, the Partnership is paid for its services by keeping a percentage of the NGLs produced and a percentage of the residue gas resulting from processing the natural gas. Under the percentage-of-index contract type, the Partnership earns revenue by purchasing wellhead natural gas at a percentage of the index price and selling processed natural gas and NGLs at a price approximating the index price to third parties. The Partnership generally reports revenue gross in the consolidated statements of operations when it acts as the principal, takes title to the product, and incurs the risks and rewards of ownership. Revenue for fee-based arrangements is presented net, because the Partnership takes the role of an agent for the producers. Allowance for doubtful accounts is determined based on historical write-off experience and specific identification.

Derivative Instruments. The Partnership's net income and cash flows are subject to volatility stemming from changes in market prices such as natural gas prices, NGLs prices, processing margins and interest rates. The Partnership uses product-specific swaps to create offsetting positions to specific commodity price exposures, and uses interest rate swap contracts to create offsetting positions to specific interest rate exposures. Derivative financial instruments are recorded on the balance sheet at their fair value based on their settlement date. The Partnership employs derivative financial instruments in connection with an underlying asset, liability and/or anticipated transaction and not for speculative purposes. Furthermore, the Partnership regularly assesses the creditworthiness of counterparties to manage the risk of default. Derivative financial instruments qualifying for hedge accounting treatment may be designated by the Partnership as cash flow hedges. The Partnership enters into cash flow hedges to hedge the variability in cash flows related to a forecasted transaction. At inception, the Partnership formally documents the relationship between the hedging instrument and the hedged item, the risk management objectives, and the methods used for assessing and testing correlation and hedge effectiveness. The Partnership also assesses, both at the inception of the hedge and on an on-going basis, whether the derivatives are highly effective in offsetting changes in cash flows of the hedged item. If the Partnership determines that a derivative is no longer highly effective as a hedge, it would discontinues hedge accounting prospectively by including changes in the fair value of the derivative in current earnings. For cash flow hedges, changes in the derivative fair values, to the extent that the hedges are effective, are recorded as a component of accumulated other comprehensive income (loss) until the hedged transactions occur and are recognized in earnings. Any ineffective portion of a cash flow hedge's change in value is recognized immediately in earnings. In the statement of cash flows, the effects of settlements of derivative instruments are classified consistent with the related hedged transactions.

Benefits. The Partnership provides medical, dental, and other healthcare benefits to employees. The total amount incurred by the Partnership for the years ended December 31, 2013, 2012 and 2011, was $9 million, $9 million and $6 million, respectively, in operation and maintenance and general and administrative expenses, as appropriate. The Partnership also provides a matching contribution to its employee’s 401(k) accounts. Effective January 1, 2011, the Partnership’s 401(k) plan merged with and into that of Energy Transfer Partners (“ETP”). As a result of the merger, the Partnership’s matching contributions that had not yet fully vested became fully vested. All future matching contributions from the Partnership to the employee 401(k) accounts vest immediately. In addition, SUGS maintained a separate defined contribution plan during March 26, 2012 to December 31, 2012. The total amount of matching contributions for the years ended December 31, 2013, 2012 and 2011 was $7 million, $4 million and $3 million, respectively, and were recorded in operation and maintenance and general and administrative expenses as appropriate. The Partnership has no pension obligations or other post-employment benefits. Beginning January 1, 2013, the Partnership provides a 3% profit sharing contribution to employee 401(k) accounts for all employees with base compensation below a specified threshold. The contribution is in addition to the 401(k) matching contribution and employees become vested based on years of service.

Income Taxes. The Partnership is generally not subject to income taxes, except as discussed below, because its income is taxed directly to its partners. The Partnership is subject to the gross margins tax enacted by the state of Texas. The Partnership has two wholly-owned subsidiaries that are subject to income tax and provides for deferred income taxes using the asset and liability method. Accordingly, deferred taxes are recorded for differences between the tax and book basis that will reverse in future periods. The Partnership has deferred tax liabilities of $22 million as of December 31, 2013 and 2012 related to the difference between the book and tax basis of property, plant and equipment and intangible assets and they are included in other long-term liabilities in the accompanying consolidated balance sheets. The Partnership follows the guidance for uncertainties in income taxes where a liability for an unrecognized tax benefit is recorded for a tax position that does not meet the “more likely than not” criteria. The Partnership has not recorded any uncertain tax positions meeting the more likely than not criteria as of December 31, 2013 and 2012. The Partnership recognized an immaterial amount for current federal income tax expense and deferred income tax benefit for the years ended December 31, 2013, 2012, and 2011.

Although the SUGS operations were included in the Southern Union consolidated federal income tax return prior to the SUGS Acquisition, following their acquisition by the Partnership, SUGS's operations are now treated as a pass-through entity. Therefore, other than one wholly-owned subsidiary, SUGS's historical operations exclude income taxes for all periods presented.

Effective with the Partnership's acquisition of SUGS on April 30, 2013, SUGS is generally no longer subject to federal income taxes and subject only to gross margins tax in the state of Texas. Substantially all previously recorded current and deferred tax liabilities were settled with Southern Union, along with all other intercompany receivables and payables at the date of acquisition.

The IRS commenced audits of our 2007 and 2008 federal income tax returns on January 27, 2010. The IRS has now completed its audit of these returns and proposed certain adjustments. The Partnership filed a protest with the IRS to initiate the appeals process and appeal certain of these adjustments. Until this matter is fully resolved, it is not known whether any amounts ultimately recorded would be material, or how such adjustments would affect unitholders. The statute of limitations for these audits has been extended to December 31, 2014. In January 2014, the Partnership settled the 2007 through 2009 tax returns audit for a wholly-owned subsidiary for an immaterial amount.

Equity-Based Compensation. The Partnership accounts for equity-based compensation by recognizing the grant-date fair value of awards into expense as they are earned, using an estimated forfeiture rate. The forfeiture rate assumption is reviewed annually to determine whether any adjustments to expense are required.

2. Summary of Significant Accounting Policies

Use of Estimates. These consolidated financial statements have been prepared in conformity with GAAP, which includes the use of estimates and assumptions by management that affect the reported amounts of assets, liabilities, revenues, expenses and disclosure of contingent assets and liabilities that exist at the date of the financial statements. Although these estimates are based on management's available knowledge of current and expected future events, actual results could be different from those estimates.

Common Control Transactions. Entities and assets acquired from ETE and its affiliates are accounted for as common control transactions whereby the net assets acquired are combined with the Partnership's net assets at their historical amounts. If consideration transferred differs from the carrying value of the net assets acquired, the excess or deficiency is treated as a capital transaction similar to a dividend or capital contribution. To the extent that such transactions require prior periods to be recast, historical net equity amounts prior to the transaction date are reflected in predecessor equity.

Cash and Cash Equivalents. Cash and cash equivalents include temporary cash investments with original maturities of three months or less.

Equity Method Investments. The equity method of accounting is used to account for the Partnership's interest in investments of greater than 20% voting interest or where the Partnership exerts significant influence over an investee but lacks control over the investee.

Inventories. Inventories are valued at the lower of cost or market and include materials and parts primarily utilized by the Contract Services segment.

Property, Plant and Equipment. Property, plant and equipment is recorded at historical cost of construction or, upon acquisition, the fair value of the assets acquired. Gains or losses on sales or retirements of assets are included in operating income unless the disposition is treated as discontinued operations. Natural gas and NGLs used to maintain pipeline minimum pressures is and classified as property, plant and equipment. Financing costs associated with the construction of larger assets requiring ongoing efforts over a period of time are capitalized. For the years ended December 31, 2013, 2012 and 2011, the Partnership capitalized interest of $2 million, $1 million and $1 million, respectively. The costs of maintenance and repairs, which are not significant improvements, are expensed when incurred. Expenditures to extend the useful lives of the assets are capitalized.

Depreciation expense related to property, plant and equipment was $258 million, $219 million, and $138 million for the years ended December 31, 2013, 2012 and 2011, respectively. In March 2012, the Partnership recorded a $7 million "out-of-period" adjustment to depreciation expense to correct the estimated useful lives of certain assets to comply with its policy.

Depreciation of property, plant and equipment is recorded on a straight-line basis over the following estimated useful lives:

Functional Class of Property	Useful Lives (Years)
Gathering and Transmission Systems	10 - 50
Compression Equipment	2 - 30
Gas Plants and Buildings	5 - 35
Other property, plant and equipment	3 - 15

Intangible Assets. As of December 31, 2013, intangible assets consisted of trade names and customer relations, and are amortized on a straight line basis over their estimated useful lives, which is the period over which the assets are expected to contribute directly or indirectly to the Partnership's future cash flows. The estimated useful lives range from 20 to 30 years.

The Partnership assesses long-lived assets, including property, plant and equipment and intangible assets, for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability is assessed by comparing the carrying amount of an asset to undiscounted future net cash flows expected to be generated by the asset. If such assets are considered to be impaired, the impairment to be recognized is measured as the amount by which the carrying amounts exceed the fair value of the assets. The Partnership did not record any impairment in 2013, 2012 or 2011.

Goodwill. Goodwill represents the excess of the purchase price over the fair value of identifiable net assets acquired in a business combination. Goodwill is not amortized, but is tested for impairment annually based on the carrying values as of November 30 or December 31 depending on the reporting unit, or more frequently if impairment indicators arise that suggest the carrying value of goodwill may not be recovered. The Partnership has the option to first assess qualitative factors to determine whether it is more likely than not that the fair value of the reporting unit is less than its carrying amount as a basis for determining whether further impairment testing is necessary. Impairment is indicated when the carrying amount of a reporting unit exceeds its fair value. To estimate the fair value of the reporting units, the Partnership makes estimates and judgments about future cash flows, as well as revenues, cost of sales, operating expenses, capital expenditures and net working capital based on assumptions that are consistent with the Partnership's most recent forecast. At the time it is determined that an impairment has occurred, the carrying value of the goodwill is written down to its fair value. The Partnership did not record any impairment in 2013, 2012 or 2011.

Other Assets, net. Other assets, net primarily consists of debt issuance costs, which are capitalized and amortized to interest expense, net over the life of the related debt.

Gas Imbalances. Quantities of natural gas or NGLs over-delivered or under-delivered related to imbalance agreements are recorded monthly as other current assets or other current liabilities using then current market prices or the weighted average prices of natural gas or NGLs at the plant or system pursuant to imbalance agreements for which settlement prices are not contractually established. Within certain volumetric limits determined at the sole discretion of the creditor, these imbalances are generally settled by deliveries of natural gas. Imbalance receivables and payables as of December 31, 2013 and 2012 were immaterial.

Asset Retirement Obligations. Legal obligations associated with the retirement of long-lived assets are recorded at fair value at the time the obligations are incurred, if a reasonable estimate of fair value can be made. Present value techniques are used which reflect assumptions such as removal and remediation costs, inflation, and profit margins that third parties would demand to settle the amount of the future obligation. The Partnership does not include a market risk premium for unforeseeable circumstances in its fair value estimates because such a premium cannot be reliably estimated. Upon initial recognition of the liability, costs are capitalized as a part of the long-lived asset and allocated to expense over the useful life of the related asset. The liability is accreted to its present value each period with accretion being recorded to operating expense with a corresponding increase in the carrying amount of the liability. The ARO assets and liabilities were immaterial as of December 31, 2013.

Environmental. The Partnership's operations are subject to federal, state and local laws and rules and regulations regarding water quality, hazardous and solid waste management, air quality control and other environmental matters. These laws, rules and regulations require the Partnership to conduct its operations in a specified manner and to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections and other approvals. Failure to comply with applicable environmental laws, rules and regulations may expose the Partnership to significant fines, penalties and/or interruptions in operations. The Partnership's environmental policies and procedures are designed to achieve compliance with such applicable laws and regulations. These evolving laws and regulations and claims for damages to property, employees, other persons and the environment resulting from current or past operations may result in significant expenditures and liabilities in the future.

Predecessor Equity. Predecessor equity included on the consolidated statement of partners' capital and noncontrolling interest represents SUGS member's capital prior to the acquisition date (April 30, 2013).

Revenue Recognition. The Partnership earns revenue from (i) domestic sales of natural gas, NGLs and condensate, (ii) natural gas gathering, processing and transportation, and (iii) contract compression and treating services. Revenue associated with sales of natural gas, NGLs and condensate are recognized when title passes to the customer, which is when the risk of ownership passes to the purchaser and physical delivery occurs. Revenue associated with transportation and processing fees are recognized when the service is provided. For contract compression and contract treating services, revenue is recognized when the service is performed. For gathering and processing services, the Partnership receives either fees or commodities from natural gas producers depending on the type of contract. Commodities received are in turn sold and recognized as revenue in accordance with the criteria outlined above. Under the percentage-of-proceeds contract type, the Partnership is paid for its services by keeping a percentage of the NGLs produced and a percentage of the residue gas resulting from processing the natural gas. Under the percentage-of-index contract type, the Partnership earns revenue by purchasing wellhead natural gas at a percentage of the index price and selling processed natural gas and NGLs at a price approximating the index price to third parties. The Partnership generally reports revenue gross in the consolidated statements of operations when it acts as the principal, takes title to the product, and incurs the risks and rewards of ownership. Revenue for fee-based arrangements is presented net, because the Partnership takes the role of an agent for the producers. Allowance for doubtful accounts is determined based on historical write-off experience and specific identification.

Derivative Instruments. The Partnership's net income and cash flows are subject to volatility stemming from changes in market prices such as natural gas prices, NGLs prices, processing margins and interest rates. The Partnership uses product-specific swaps to create offsetting positions to specific commodity price exposures, and uses interest rate swap contracts to create offsetting positions to specific interest rate exposures. Derivative financial instruments are recorded on the balance sheet at their fair value based on their settlement date. The Partnership employs derivative financial instruments in connection with an underlying asset, liability and/or anticipated transaction and not for speculative purposes. Furthermore, the Partnership regularly assesses the creditworthiness of counterparties to manage the risk of default. Derivative financial instruments qualifying for hedge accounting treatment may be designated by the Partnership as cash flow hedges. The Partnership enters into cash flow hedges to hedge the variability in cash flows related to a forecasted transaction. At inception, the Partnership formally documents the relationship between the hedging instrument and the hedged item, the risk management objectives, and the methods used for assessing and testing correlation and hedge effectiveness. The Partnership also assesses, both at the inception of the hedge and on an on-going basis, whether the derivatives are highly effective in offsetting changes in cash flows of the hedged item. If the Partnership determines that a derivative is no longer highly effective as a hedge, it would discontinues hedge accounting prospectively by including changes in the fair value of the derivative in current earnings. For cash flow hedges, changes in the derivative fair values, to the extent that the hedges are effective, are recorded as a component of accumulated other comprehensive income (loss) until the hedged transactions occur and are recognized in earnings. Any ineffective portion of a cash flow hedge's change in value is recognized immediately in earnings. In the statement of cash flows, the effects of settlements of derivative instruments are classified consistent with the related hedged transactions.

Benefits. The Partnership provides medical, dental, and other healthcare benefits to employees. The total amount incurred by the Partnership for the years ended December 31, 2013, 2012 and 2011, was $9 million, $9 million and $6 million, respectively, in operation and maintenance and general and administrative expenses, as appropriate. The Partnership also provides a matching contribution to its employee's 401(k) accounts. Effective January 1, 2011, the Partnership's 401(k) plan merged with and into that of Energy Transfer Partners ("ETP"). As a result of the merger, the Partnership's matching contributions that had not yet fully vested became fully vested. All future matching contributions from the Partnership to the employee 401(k) accounts vest immediately. In addition, SUGS maintained a separate defined contribution plan during March 26, 2012 to December 31, 2012. The total amount of matching contributions for the years ended December 31, 2013, 2012 and 2011 was $7 million, $4 million and $3 million, respectively, and were recorded in operation and maintenance and general and administrative expenses as appropriate. The Partnership has no pension obligations or other post-employment benefits. Beginning January 1, 2013, the Partnership provides a 3% profit sharing contribution to employee 401(k) accounts for all employees with base compensation below a specified threshold. The contribution is in addition to the 401(k) matching contribution and employees become vested based on years of service.

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Income Taxes. The Partnership is generally not subject to income taxes, except as discussed below, because its income is taxed directly to its partners. The Partnership is subject to the gross margins tax enacted by the state of Texas. The Partnership has two wholly-owned subsidiaries that are subject to income tax and provides for deferred income taxes using the asset and liability method. Accordingly, deferred taxes are recorded for differences between the tax and book basis that will reverse in future periods. The Partnership has deferred tax liabilities of $22 million as of December 31, 2013 and 2012 related to the difference between the book and tax basis of property, plant and equipment and intangible assets and they are included in other long-term liabilities in the accompanying consolidated balance sheets. The Partnership follows the guidance for uncertainties in income taxes where a liability for an unrecognized tax benefit is recorded for a tax position that does not meet the "more likely than not" criteria. The

Partnership has not recorded any uncertain tax positions meeting the more likely than not criteria as of December 31, 2013 and 2012. The Partnership recognized an immaterial amount for current federal income tax expense and deferred income tax benefit for the years ended December 31, 2013, 2012, and 2011.

Although the SUGS operations were included in the Southern Union consolidated federal income tax return prior to the SUGS Acquisition, following their acquisition by the Partnership, SUGS's operations are now treated as a pass-through entity. Therefore, other than one wholly-owned subsidiary, SUGS's historical operations exclude income taxes for all periods presented.

Effective with the Partnership's acquisition of SUGS on April 30, 2013, SUGS is generally no longer subject to federal income taxes and subject only to gross margins tax in the state of Texas. Substantially all previously recorded current and deferred tax liabilities were settled with Southern Union, along with all other intercompany receivables and payables at the date of acquisition.

The IRS commenced audits of our 2007 and 2008 federal income tax returns on January 27, 2010. The IRS has now completed its audit of these returns and proposed certain adjustments. The Partnership filed a protest with the IRS to initiate the appeals process and appeal certain of these adjustments. Until this matter is fully resolved, it is not known whether any amounts ultimately recorded would be material, or how such adjustments would affect unitholders. The statute of limitations for these audits has been extended to December 31, 2014. In January 2014, the Partnership settled the 2007 through 2009 tax returns audit for a wholly-owned subsidiary for an immaterial amount.

Equity-Based Compensation. The Partnership accounts for equity-based compensation by recognizing the grant-date fair value of awards into expense as they are earned, using an estimated forfeiture rate. The forfeiture rate assumption is reviewed annually to determine whether any adjustments to expense are required.

4. Acquisitions and Dispositions

2013

SUGS Acquisition. The SUGS Acquisition is discussed in footnote 1 - Organization and Basis of Presentation.

PVR Acquisition. In October 2013, the Partnership announced that it entered into a merger agreement with PVR Partners, L.P. ("PVR") pursuant to which the Partnership intends to merge with PVR ("PVR Acquisition"). This merger will be a unit-for-unit transaction plus a one-time $37 million cash payment to PVR unitholders which represents total consideration of $5.6 billion, including the assumption of net debt of $1.8 billion. The holders of PVR common units, PVR Class B Units and PVR Special Units ("PVR Unit(s)") will receive 1.02 Partnership common units in exchange for each PVR Unit held on the applicable record date. In November 2013, the Partnership received approval of the PVR Acquisition under the Hart-Scott-Rodino Antitrust Improvements Act. The transaction is subject to the approval of PVR's unitholders and other customary closing conditions, and is expected to close in March 2014.

The PVR Acquisition is expected to enhance our geographic diversity with a strategic presence in the Marcellus and Utica shales in the Appalachian Basin and the Granite Wash in the Mid-Continent region.

Eagle Rock Acquisition. In December, 2013, the Partnership entered into an agreement to purchase Eagle Rock Energy Partners, L.P.'s ("Eagle Rock's") midstream business for approximately $1.3 billion (the "Eagle Rock Midstream Acquisition"). This acquisition is expected to complement the Partnership's core gathering and processing business, and when combined with the PVR Acquisition, is expected to further diversify the Partnership's basin exposure in the Texas Panhandle, East Texas and South Texas. The Eagle Rock Midstream Acquisition is expected to close in the second quarter of 2014, and is subject to the approval of Eagle Rock unitholders, Hart-Scott-Rodino Antitrust Improvements Act approval and other customary closing conditions.

Hoover Energy Acquisition. On February 3, 2014, the Partnership completed its previously announced acquisition of the subsidiaries of Hoover Energy Partners, LP that are engaged in crude oil gathering, transportation and terminaling, condensate handling, natural gas gathering, treating and processing, and water gathering and disposal services in the southern Delaware Basin in West Texas. The consideration paid by the Partnership was valued at $281.6 million (subject to customary post-closing adjustments) and consisted of (i) 4,040,471 Regency common units issued to Hoover and (ii) $183.6 million in cash. A portion of the consideration is being held in escrow as security for certain indemnification claims. The Partnership financed the cash portion of the purchase price through borrowings under its revolving credit facility. The Partnership will account for the acquisition of Hoover using the acquisition method of accounting, which requires, among other things, that assets acquired and liabilities assumed be recognized on the balance sheet at their fair values as of the acquisition date. Management's evaluation of the assigned fair values is ongoing as the transaction was recently completed and therefore the Partnership was not able to complete the preliminary allocation of the purchase price to the acquired assets and liabilities prior to the issuance of these financial statements.

2011

Lone Star. On May 2, 2011, the Partnership contributed $593 million in cash to Lone Star NGL LLC ("Lone Star"), in exchange for its 30% interest. Lone Star, a newly formed joint venture that is owned 70% by ETP and 30% by the Partnership, completed its acquisition of all of the membership interest in LDH, a wholly-owned subsidiary of Louis Dreyfus Highbridge Energy LLC for $1.98 billion in cash. To fund a portion of this capital contribution, the Partnership issued 8,500,001 Regency common units representing limited partnership interests with net proceeds of $204 million. The remaining portion of the Partnership's capital contribution was funded by additional borrowings under its revolving credit facility.

Ranch JV. On December 2, 2011, Ranch Westex JV LLC ("Ranch JV") was formed by the Partnership, Anadarko Pecos Midstream LLC and Chesapeake West Texas Processing, L.L.C., each owning a 33.33% interest in the joint venture. Ranch JV processes natural gas delivered from the NGLs-rich Bone Spring and Avalon shale formations in West Texas.

5. Investments in Unconsolidated Affiliates

As of December 31, 2013, the Partnership has a 49.99% general partner interest in RIGS Haynesville Partnership Co. ("HPC"), a 50% membership interest in Midcontinent Express Pipeline LLC ("MEP"), a 30% membership interest in Lone Star, a 33.33% membership interest in Ranch JV, and a 50% membership interest in Grey Ranch. The Partnership acquired a 33.33% membership interest in Ranch JV in December 2011, a 30% interest in Lone Star in May 2011, a 49.9% interest in MEP in May 2010 and a 0.1% interest in MEP in September 2011. The carrying value of the Partnership's investment in each of the unconsolidated affiliates as of December 31, 2013 and 2012 is as follows:

	December 31, 2013	December 31, 2012
HPC	$ 442	$ 650
MEP	548	581
Lone Star	1,070	948
Ranch JV	36	35
Grey Ranch	1	—
	$ 2,097	$ 2,214

The following tables summarize the changes in the Partnership's investment activities in each of the unconsolidated affiliates for the years ended December 31, 2013, 2012 and 2011:

	Year Ended December 31, 2013				
	HPC [2]	MEP	Lone Star	Ranch JV	Grey Ranch
Contributions	$ —	$ —	$ 137	$ 2	$ —
Distributions	238	72	79	2	—
Share of net income	36	39	64	1	1
Amortization of excess fair value of investment [1]	(6)	—	—	—	—

	Year Ended December 31, 2012				
	HPC	MEP	Lone Star	Ranch JV	Grey Ranch
Contributions	$ —	$ —	$ 343	$ 36	$ —
Distributions	61	75	68	—	—
Share of net income	35	42	44	(1)	(9)
Amortization of excess fair value of investment [1]	(6)	—	—	—	—

	Year Ended December 31, 2011				
	HPC	MEP[3]	Lone Star[4]	Ranch JV	Grey Ranch
Contributions	$ —	$ —	$ 645	$ —	N/A
Purchase of additional interest	—	1	—	—	N/A
Distributions	65	83	22	—	N/A
Return of investment	—	—	23	—	N/A
Share of net income	55	43	28	—	N/A
Amortization of excess fair value of investment [1]	(6)	—	—	—	N/A

(1) The Partnership's investment in HPC was adjusted to its fair value on May 26, 2010 and the excess fair value over net book value was comprised of two components: (1) $155 million was attributed to HPC's long-lived assets and is being amortized as a reduction of income from unconsolidated affiliates over the useful lives of the respective assets, which vary from 15 to 30 years, and (2) $32 million could not be attributed to a specific asset and therefore will not be amortized in future periods.

(2) HPC entered into a $500 million 5-year revolving credit facility in September 2013, pursuant to which the Partnership pledged its 49.99% equity interest in HPC. Upon closing such credit facility, HPC borrowed $370 million to fund a non-recurring return of investment to its partners of which the Partnership received $185 million. The amount outstanding under this facility was $445 million as of December 31, 2013. The Partnership's contingent obligation with respect to the outstanding borrowings under this facility was $222 million at December 31, 2013.

(3) In September 2011, the Partnership purchased an additional 0.1% interest in MEP from ETP for $1 million in cash, bringing the total membership interest to 50%.

(4) For the period from initial contribution, May 2, 2011, to December 31, 2011.

N/A The Partnership acquired a 50% interest in Grey Ranch in March 2012, as part of the SUGS Acquisition in April 2013.

6. Derivative Instruments

Policies. The Partnership established comprehensive risk management policies and procedures to monitor and manage the market risks associated with commodity prices, counterparty credit, and interest rates. The General Partner is responsible for delegation of transaction authority levels, and the Audit and Risk Committee of the General Partner is responsible for the overall management of these risks, including monitoring exposure limits. The Audit and Risk Committee receives regular briefings on exposures and overall risk management in the context of market activities.

Commodity Price Risk. The Partnership is a net seller of NGLs, condensate and natural gas as a result of its gathering and processing operations. The prices of these commodities are impacted by changes in the supply and demand as well as other market forces. Both the Partnership's profitability and cash flow are affected by the inherent volatility of these commodities which could adversely affect its ability to make distributions to its unitholders. The Partnership manages this commodity price exposure through an integrated strategy that includes management of its contract portfolio, matching sales prices of commodities with purchases, optimization of its portfolio by monitoring basis and other price differentials in operating areas, and the use of derivative contracts. In some cases, the Partnership may not be able to match pricing terms or to cover its risk to price exposure with financial hedges, and it may be exposed to commodity price risk. Speculative positions with derivative contracts are prohibited under the Partnership's policies.

The Partnership has swap contracts settled against NGLs (natural gas liquids, including propane, normal butane, iso butane and natural gasoline), condensate and natural gas market prices. The Partnership also had put options settled against ethane, which expired in December 2012.

On January 1, 2012, the Partnership de-designated its swap contracts and began accounting for these contracts using the mark-to-market method of accounting. As of December 31, 2013, the Partnership had an immaterial amount in net hedging gains in AOCI, all of which will be amortized to earnings over the next three months.

As of December 31, 2012, SUGS had outstanding receive-fixed natural gas price swaps with a total notional amount of 4,562,500 MMBtu for 2012. These natural gas price swaps were accounted for as cash flow hedges, with effective portion of changes in their fair value recorded to AOCI and reclassified into revenues in the same period which the forecasted natural gas sales impact earnings. As of April 30, 2013, in connection with the SUGS Acquisition, these outstanding hedges were terminated.

Interest Rate Risk. The Partnership is exposed to variable interest rate risk as a result of borrowings under its revolving credit facility. The Partnership's $250 million interest rate swaps expired in April 2012. As of December 31, 2013, the Partnership had $510 million of outstanding borrowings exposed to variable interest rate risk.

Credit Risk. The Partnership's resale of NGLs, condensate, and natural gas exposes it to credit risk, as the margin on any sale is generally a very small percentage of the total sales price. Therefore, a credit loss can be very large relative to overall profitability on these transactions. The Partnership monitors credit exposure and attempts to ensure that it issues credit only to creditworthy counterparties and that in appropriate circumstances any such extension of credit is backed by adequate collateral, such as a letter of credit or parental guarantee from a parent company with potentially better credit.

The Partnership is exposed to credit risk from its derivative counterparties. The Partnership does not require collateral from these counterparties. The Partnership deals primarily with financial institutions when entering into financial derivatives, and utilizes master netting agreements that allow for netting of swap contract receivables and payables in the event of default by either party.

If the Partnership's counterparties failed to perform under existing swap contracts, the Partnership's maximum loss as of December 31, 2013 was $4 million, which would be reduced by less than $1 million due to the netting feature. The Partnership has elected to present assets and liabilities under master netting agreements gross on the consolidated balance sheets.

Embedded Derivatives. The Regency Series A Preferred Units contain embedded derivatives which are required to be bifurcated and accounted for separately, such as the holders' conversion option and the Partnership's call option. These embedded derivatives are accounted for using mark-to-market accounting. The Partnership does not expect the embedded derivatives to affect its cash flows.

The Partnership's derivative assets and liabilities, including credit risk adjustments, as of December 31, 2013 and 2012 are detailed below:

	Assets		Liabilities	
	December 31, 2013	**December 31, 2012**	**December 31, 2013**	**December 31, 2012**
Derivatives designated as cash flow hedges				
Current amounts				
Commodity contracts	$ —	$ —	$ —	$ 5
Total cash flow hedging instruments	—	—	—	5
Derivatives not designated as cash flow hedges				
Current amounts				
Commodity contracts	$ 3	$ 4	$ 9	$ 1
Long-term amounts				
Commodity contracts	1	1	—	—
Embedded derivatives in Series A Preferred Units	—	—	19	25
Total derivatives	$ 4	$ 5	$ 28	$ 31

The Partnership's statements of operations for the years ended December 31, 2013, 2012 and 2011 were impacted by derivative instruments activities as detailed below:

		Years Ended December 31,		
		2013	**2012**	**2011**
Derivatives in cash flow hedging relationships:		**Change in Value Recognized in AOCI on Derivatives (Effective Portion)**		
Commodity derivatives		$ —	$ (4)	$ (13)
Derivatives in cash flow hedging relationships:	**Location of Gain/(Loss) Recognized in Income**	**Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)**		
Commodity derivatives	Revenue	$ —	$ 6	$ (19)

		Years Ended December 31,		
		2013	**2012**	**2011**
Derivatives not designated in a hedging relationship:	**Location of Gain/(Loss) Recognized in Income**	**Amount of Gain/(Loss) from De-designation Amortized from AOCI into Income**		
Commodity derivatives	Revenue	$ —	$ (5)	$ —
Derivatives not designated in a hedging relationship:	**Location of Gain/(Loss) Recognized in Income**	**Amount of Gain/(Loss) Recognized in Income on Derivatives**		
Commodity derivatives	Revenue	$ (9)	$ 16	$ —
Embedded derivatives	Other income & deductions	6	14	18
		$ (3)	$ 30	$ 18

7. Long-term Debt

Obligations in the form of senior notes and borrowings under the credit facilities are as follows:

	December 31, 2013	December 31, 2012
Senior notes	$ 2,800	$ 1,965
Revolving loans	510	192
Total	3,310	2,157
Less: current portion	—	—
Long-term debt	$ 3,310	$ 2,157
Availability under revolving credit facility:		
Total credit facility limit	$ 1,200	$ 1,150
Revolving loans	(510)	(192)
Letters of credit	(14)	(12)
Total available	$ 676	$ 946

Long-term debt maturities as of December 31, 2013 for each of the next five years are as follows:

Year Ended December 31,	Amount
2014	$ —
2015	—
2016	—
2017	—
2018	600
Thereafter	2,710
Total	$ 3,310

Revolving Credit Facility

In the year ended December 31, 2013, 2012 and 2011 the Partnership borrowed $1.46 billion, $1.56 billion and $940 million, respectively, under its revolving credit facility; these borrowings were to fund capital expenditures and acquisitions. During the same periods, the Partnership repaid $1.1 billion, $1.70 billion and $893 million, respectively, with proceeds from equity offerings and issuances of senior notes.

In May 2013, Regency Gas Services, LP, a wholly-owned subsidiary of Regency Energy Partners LP, entered into the Sixth Amended and Restated Credit Agreement to increase the commitment to $1.2 billion with a $300 million uncommitted incremental facility and extended the maturity date to May 21, 2018. The material differences between the Fifth and Sixth Amended and Restated Credit Agreement include:

- A 75 bps decrease in pricing, with an additional 50 bps decrease upon the achievement of an investment grade rating;
- No limitation on the maximum amount that the loan parties may invest in joint ventures existing on the date of the credit agreement so long as the Partnership is in pro forma compliance with the financial covenants;
- The addition of a “Restricted Subsidiary” structure such that certain designated subsidiaries are not subject to the credit facility covenants and do not guarantee the obligations thereunder or pledge their assets in support thereof;
- The addition of provisions such that upon the achievement of an investment grade rating by the Partnership, the collateral package will be released; the facility will become unsecured; and the covenant package will be significantly reduced;
- An eight-quarter increase in the permitted Total Leverage Ratio; and
- After March 2015, an increase in the permitted total leverage ratio for the two fiscal quarters following any $50 million or greater acquisition.

The Partnership capitalized $6 million of net loan fees which is being amortized over the remaining term.

The revolving credit facility and the guarantees are senior to the Partnership’s and the guarantors’ unsecured obligations, to the extent of the value of the assets securing such obligations.

As of December 31, 2013, the Partnership was in compliance in all material respects with all of the financial covenants contained within the new credit agreement.

The outstanding balance under the revolving credit facility bears interest at LIBOR plus a margin or alternate base rate (equivalent to the U.S. prime lending rate) plus a margin, or a combination of both. The alternate base rate used to calculate interest on base rate loans will be calculated based on the greatest to occur of a base rate, a federal funds effective rate plus 0.50% and an adjusted one-month LIBOR rate plus 1.00%. The applicable margin shall range from 0.625% to 1.50% for base rate loans, 1.625% to 2.50% for Eurodollar loans. The weighted average interest rate on the total amounts outstanding under the Partnership's revolving credit facility was 2.17% and 2.93% as of December 31, 2013 and 2012, respectively.

RGS must pay (i) a commitment fee ranging from 0.30% to 0.45% per annum of the unused portion of the revolving loan commitments, (ii) a participation fee for each revolving lender participating in letters of credit ranging from 1.625% to 2.50% per annum of the average daily amount of such lender's letter of credit exposure and (iii) a fronting fee to the issuing bank of letters of credit equal to 0.20% per annum of the average daily amount of the letter of credit exposure. These fees are included in interest expense, net in the consolidated statement of operations.

The revolving credit facility contains financial covenants requiring RGS and its subsidiaries to maintain a debt to consolidated EBITDA (as defined in the credit agreement) ratio less than 5.00 for the first eight quarters (after March 2015, an increase is allowed in the permitted total leverage ratio for the first two fiscal quarters following any $50 million or greater acquisition), consolidated EBITDA to consolidated interest expense ratio greater than 2.50 and a secured debt to consolidated EBITDA ratio less than 3.25. At December 31, 2013 and 2012, RGS and its subsidiaries were in compliance with these covenants.

The revolving credit facility restricts the ability of RGS to pay dividends and distributions other than reimbursements of the Partnership for expenses and payment of dividends to the Partnership to the amount of available cash (as defined) so long as no default or event of default has occurred or is continuing. The revolving credit facility also contains various covenants that limit (subject to certain exceptions), among other things, the ability of RGS to:

- incur indebtedness;
- grant liens;
- enter into sale and leaseback transactions;
- make certain investments, loans and advances;
- dissolve or enter into a merger or consolidation;
- enter into asset sales or make acquisitions;
- enter into transactions with affiliates;
- prepay other indebtedness or amend organizational documents or transactions documents (as defined in the revolving credit facility);
- issue capital stock or create subsidiaries; or
- engage in any business other than those businesses in which it was engaged at the time of the effectiveness of the revolving credit facility or reasonable extension thereof.

In February 2014, RGS entered into the first Amendment to the Sixth Amended and restated Credit Agreement to, among other things, expressly permit the pending PVR and Eagle Rock acquisitions, and to increase the commitment to $1.5 billion and increase the uncommitted incremental facility to $500 million. The amendment will specifically allows the Partnership to assume the series of PVR senior notes that mature prior to the credit agreement.

Senior Notes

In May 2009, the Partnership and Regency Energy Finance Corp., a wholly-owned subsidiary of the Partnership, issued $250 million of senior notes that mature on June 1, 2016 (the "2016 Notes"). The 2016 Notes bear interest at 9.375% with interest payable semi-annually in arrears on June 1 and December 1. In May 2012, the Partnership redeemed 35%, or $88 million, of the 2016 Notes, bringing the total outstanding principal amount to $163 million. A redemption premium of $8 million was charged to loss on debt refinancing, net in the consolidated statement of operations and $4 million of accrued interest was paid. The Partnership also wrote off the unamortized loan fee of $1 million and unamortized bond premium of $2 million to loss on debt refinancing, net in the consolidated statement of operations. In June 2013, the Partnership redeemed all amounts outstanding 2016 Notes for $178 million cash, inclusive of accrued and unpaid interest of $7 million and other fees and expenses.

The Partnership and Finance Corp. have outstanding the following series of senior notes (collectively "Senior Notes"):

- $600 million in aggregate principal amount of our 6 ⅞% senior notes due December 1, 2018 (the "2018 Notes") with interest payable semi-annually in arrears on June 1 and December 1;
- $400 million in aggregate principal amount of our 5 ¾% senior notes due September 1, 2020 (the "2020 Notes") with interest payable semi-annually in arrears on March 1 and September 1;
- $500 million in aggregate principal amount of our 6 ½% senior notes due July 15, 2021 (the "2021 Notes") with interest payable semi-annually in arrears on January 15 and July 15;
- $900 million in aggregate principal of our 5 ⅞% senior notes due March 1, 2022 (the "2022 Notes") issued in February 2014, with interest payable semi-annually in arrears on March 1 and September 1;
- $700 million in aggregate principal amount of our 5 ½% senior notes due April 15, 2023 (the "2023 5 ½% Notes") with interest payable semi-annually in arrears on April 15 and October 15; and
- $600 million in aggregate principal amount of our 4 ½% senior notes due November 1, 2023 (the "2023 4 ½% Notes") with interest payable semi-annually in arrears on May 1 and November 1.

The Senior Notes are guaranteed by our existing consolidated subsidiaries except Finance Corp and ELG.

The Senior Notes are redeemable at any time prior to the dates specified below at a price equal to 100% of the principal amount of the applicable series, plus a make-whole premium and accrued and unpaid interest, if any, to the redemption date.

- 2018 Notes - Beginning December 1, 2014 100% may be redeemed at fixed redemption price of 103.438% (December 1, 2015 - 101.719% and December 1, 2016 and thereafter - 100%) plus accrued and unpaid interest, if any, to the redemption date
- 2020 Notes - Redeemable, in whole or in part, prior to June 1, 2020 at 100% of the principal amount plus a make-whole premium and accrued and unpaid interest, if any, to the redemption date; redeemable, in whole or in part, on or after June 1, 2020 at 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date
- 2021 Notes - Any time prior to July 15, 2014, up to 35% may be redeemed at a price of 106.5% plus accrued and unpaid interest, if any; beginning July 15, 2016, 100% may be redeemed at fixed redemption price of 103.25% (July 15, 2017 - 102.167%, July 15, 2018 - 101.083% and July 15, 2019 and thereafter - 100%) plus accrued and unpaid interest, if any, to the redemption date
- 2022 Notes - Redeemable, in whole or in part, prior to December 1, 2021 at 100% at the principal amount plus a make-whole premium and accrued and unpaid interest, if any, to the redemption date; redeemable, in whole or in part, on or after December 1, 2021 at 100% at the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date
- 2023 5 ½% Notes - Any time prior to October 15, 2015, up to 35% may be redeemed at a price of 105.5% plus accrued and unpaid interest, if any; beginning October 15, 2017, 100% may be redeemed at fixed redemption price of 102.75% (October 15, 2018 - 101.833%, October 15, 2019 - 100.917% and October 15, 2020 and thereafter - 100%) plus accrued and unpaid interest, if any, to the redemption date
- 2023 4 ½% Notes - Redeemable, in whole or in part, prior to August 1, 2023 at 100% of the principal amount plus a make-whole premium and accrued and unpaid interest, if any, to the redemption date; redeemable, in whole or in part, on or after August 1, 2023 at 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date

Upon a change of control followed by a ratings downgrade within 90 days of a change of control, each note holder of the Senior Notes will be entitled to require us to purchase all or a portion of its notes at a purchase price of 101% plus accrued and unpaid interest, if any. The Partnership's ability to purchase the Senior Notes upon a change of control will be limited by the terms of our debt agreements, including the Partnership's revolving credit facility.

The existing senior notes contain various covenants that limit, among other things, our ability, and the ability of certain of our subsidiaries, to:

- incur additional indebtedness;
- pay distributions on, or repurchase or redeem our equity interests;
- make certain investments;
- incur liens;
- enter into certain types of transactions with affiliates; and
- sell assets or consolidate or merge with or into other companies.

If the Senior Notes achieve investment grade ratings by both Moody’s and Standard & Poor’s and no default or event of default has occurred and is continuing, we will no longer be subject to many of the foregoing covenants. At December 31, 2013, we were in compliance with these covenants.

8. Intangible Assets

Activity related to intangible assets, net consisted of the following:

	Customer Relations	Trade Names	Total
Balance at January 1, 2012	$ 681	$ 60	$ 741
Amortization	(26)	(3)	(29)
Balance at December 31, 2012	655	57	712
Amortization	(26)	(4)	(30)
Balance at December 31, 2013	$ 629	$ 53	$ 682

The average remaining amortization periods for customer relations and trade names are 24 and 16 years, respectively. The expected amortization of the intangible assets for each of the five succeeding years is $30 million.

9. Fair Value Measures

The fair value measurement provisions establish a three-tiered fair value hierarchy that prioritizes inputs to valuation techniques used in fair value calculations. The three levels of inputs are defined as follows:

- Level 1—unadjusted quoted prices for identical assets or liabilities in active accessible markets;
- Level 2—inputs that are observable in the marketplace other than those classified as Level 1; and
- Level 3—inputs that are unobservable in the marketplace and significant to the valuation.

Entities are encouraged to maximize the use of observable inputs and minimize the use of unobservable inputs. If a financial instrument uses inputs that fall in different levels of the hierarchy, the instrument will be categorized based upon the lowest level of input that is significant to the fair value calculation.

The Partnership's financial assets and liabilities measured at fair value on a recurring basis are derivatives related to commodity swaps and embedded derivatives in the Regency Series A Preferred Units. Derivatives related to commodity swaps are valued using observable inputs for similar instruments and incorporate Level 1 and Level 2 inputs. Embedded derivatives related to the Regency Series A Preferred Units are valued using a binomial lattice model. The market inputs utilized in the model include credit spread, probabilities of the occurrence of certain events, common unit price, dividend yield, and expected volatility, and are classified as Level 3.

The following table presents the Partnership’s derivative assets and liabilities measured at fair value on a recurring basis:

	Fair Value Measurement at December 31, 2013			Fair Value Measurement at December 31, 2012		
	Fair Value Total	Level 2	Level 3	Fair Value Total	Level 2	Level 3
Assets						
Commodity Derivatives:						
Natural Gas	$ 2	$ 2	$ —	$ 2	$ 2	$ —
Natural Gas Liquids	2	2	—	1	1	—
Condensate	—	—	—	2	2	—
Total Assets	$ 4	$ 4	$ —	$ 5	$ 5	$ —
Liabilities						
Commodity Derivatives:						
Natural Gas	$ 4	$ 4	$ —	$ 5	$ 5	$ —
Natural Gas Liquids	4	4	—	1	1	—
Condensate	1	1	—	—	—	—
Embedded Derivatives in Regency Series A Preferred Units	19	—	19	25	—	25
Total Liabilities	$ 28	$ 9	$ 19	$ 31	$ 6	$ 25

The following table presents the material unobservable inputs used to estimate the fair value of the embedded derivatives in the Regency Series A Preferred Units:

Unobservable Input	December 31, 2013
Credit Spread	4.16%
Volatility	23.71%

Changes in the Partnership's cost of equity and U.S. Treasury yields would cause a change in the credit spread used to value the embedded derivatives. Changes in the Partnership's historical unit price volatility would cause a change in the volatility used to value the embedded derivatives.

The following table presents the changes in Level 3 derivatives measured on a recurring basis for the years ended December 31, 2013 and 2012. There were no transfers between Level 2 and Level 3 derivatives for the years ended December 31, 2013 and 2012.

	Embedded Derivatives in Series A Preferred Units
Balance at January 1, 2012	$ 39
Change in fair value	(14)
Balance at December 31, 2012	25
Change in fair value, net of gain at conversion of $26 million	(6)
Balance at December 31, 2013	$ 19

The carrying amount of cash and cash equivalents, accounts receivable and accounts payable approximates fair value due to their short-term maturities. Long-term debt, other than the Senior Notes, is comprised of borrowings under which interest accrues under a floating interest rate structure. Accordingly, the carrying value approximates fair value.

The aggregate fair value and carrying amount of the Senior Notes at December 31, 2013 was $2.83 billion and $2.80 billion, respectively. As of December 31, 2012, the aggregate fair value and carrying amount of the Senior Notes was $2.13 billion and $1.97 billion, respectively. The fair value of the Senior Notes is a Level 1 valuation based on third party market value quotations.

10. Leases

The following table is a schedule of future minimum lease payments for office space and certain equipment leased by the Partnership, that had initial or remaining non-cancelable lease terms in excess of one year as of December 31, 2013:

For the year ending December 31,	Operating Lease
2014	$ 3
2015	3
2016	2
2017	2
2018	2
Thereafter	34
Total minimum lease payments	$ 46

Total rent expense for operating leases, including those leases with terms of less than one year, was $11 million, $11 million and $3 million for the years ended December 31, 2013, 2012 and 2011, respectively.

11. Commitments and Contingencies

Legal. The Partnership is involved in various claims, lawsuits and audits by taxing authorities incidental to its business. These claims and lawsuits in the aggregate are not expected to have a material adverse effect on the Partnership's business, financial condition, results of operations or cash flows.

PVR Shareholder Litigation. Five putative class action lawsuits challenging the PVR Acquisition are currently pending. All of the cases name PVR, PVR GP and the current directors of PVR GP, as well as the Partnership and the General Partner (collectively, the "Regency Defendants"), as defendants. Each of the lawsuits has been brought by a purported unitholder of PVR, both individually and on behalf of a putative class consisting of public unitholders of PVR. The lawsuits generally allege, among other things, that the directors of PVR GP breached their fiduciary duties to unitholders of PVR, that PVR GP, PVR and the Regency Defendants aided and abetted the directors of PVR GP in the alleged breach of these fiduciary duties, and, as to the actions in federal court, that some or all of PVR, PVR GP, and the directors of PVR GP violated Section 14(a) of the Exchange Act and Rule 14a-9 promulgated thereunder and Section 20(a) of the Exchange Act. The lawsuits purport to seek, in general, (i) injunctive relief, (ii) disclosure of certain additional information concerning the transaction, (iii) in the event the merger is consummated, rescission or an award of rescissory damages, (iv) an award of plaintiffs' costs and (v) the accounting for damages allegedly causes by the defendants to these actions, and, (iv) such further relief as the court deems just and proper. The styles of the pending cases are as follows: David Naiditch v. PVR Partners, L.P., et al. (Case No. 9015-VCL) in the Court of Chancery of the State of Delaware); Charles Monatt v. PVR Partners, LP, et al. (Case No. 2013-10606) and Saul Srour v. PVR Partners, L.P., et al. (Case No. 2013-011015), each pending in the Court of Common Pleas for Delaware County, Pennsylvania; Stephen Bushansky v. PVR Partners, L.P., et al. (C.A. No. 2:13-cv-06829-HB); and Mark Hinnau v. PVR Partners, L.P., et al. (C.A. No. 2:13-cv-07496-HB), pending in the United States District Court for the Eastern District of Pennsylvania.

On January 28, 2014, the defendants entered into a Memorandum of Understanding ("MOU") with Monatt, Srour, Bushansky, Naiditch and Hinnau pursuant to which defendants and the referenced plaintiffs agreed in principle to a settlement of their lawsuits ("Settled Lawsuits"), which will be memorialized in a separate settlement agreement, subject to customary conditions, including consummation of the PVR Acquisition, completion of certain confirmatory discovery, class certification and final approval by the Court of Common Pleas for Delaware County, Pennsylvania. If the Court approves the settlement, the Settled Lawsuits will be dismissed with prejudice and all defendants will be released from any and all claims relating to the Settled Lawsuits.

The settlement will not affect any provisions of the merger agreement or the form or amount of consideration to be received by PVR unitholders in the PVR Acquisition. The defendants have denied and continue to deny any wrongdoing or liability with respect to the plaintiffs' claims in the aforementioned litigation and have entered into the settlement to eliminate the uncertainty, burden, risk, expense, and distraction of further litigation.

Environmental. The Partnership is responsible for environmental remediation at certain sites on its gathering and processing systems, resulting primarily from releases of hydrocarbons. The Partnership's remediation program typically involves the management of contaminated soils and may involve remediation of groundwater. Activities vary with site conditions and locations, the extent and nature of the contamination, remedial requirements and complexity. The ultimate liability and total costs associated with these sites will depend upon many factors.

The table below reflects the environmental liabilities recorded in the consolidated balance sheet at December 31, 2013 and 2012 where management believes a loss is probable and reasonably estimable. The Partnership does not have any material environmental remediation matters assessed as reasonably possible that would require disclosure in the financial statements.

	December 31, 2013	December 31, 2012
Current	$ 2	$ 5
Noncurrent	6	7
Total environmental liabilities	$ 8	$ 12

The Partnership made expenditures related to environmental remediation of $5 million for the year ended December 31, 2013.

Air Quality Control. The Partnership is currently negotiating settlements to certain enforcement actions by the NMED and the TCEQ. The TCEQ recently initiated a state-wide emissions inventory for the sulfur dioxide emissions from sites with reported emissions of 10 tons per year or more. If this data demonstrates that any source or group of sources may cause or contribute to a violation of the National Ambient Air Quality Standards, they must be sufficiently controlled to ensure timely attainment of the standard. This may potentially affect three SUGS recovery units in Texas. It is unclear at this time how the NMED will address the sulfur dioxide standard.

Compliance Orders from the NMED. SUGS has been in discussions with the NMED concerning allegations of violations of New Mexico air regulations related to the Jal #3 and Jal #4 facilities. Hearings on the COs were delayed until March 2014 to allow the parties to pursue substantive settlement discussions. The Partnership has meritorious defenses to the NMED claims and can offer significant mitigating factors to the claimed violations. The Partnership has recorded a liability of less than $1 million related to the claims and will continue to assess its potential exposure to the allegations as the matters progress.

CDM Sales Tax Audit. CDM Resource Management LLC ("CDM"), a subsidiary of the Partnership, has historically claimed the manufacturing exemption from sales tax in Texas, as is common in the industry. The exemption is based on the fact that CDM's natural gas compression equipment is used in the process of treating natural gas for ultimate use and sale. In a recent audit by the Texas Comptroller's office, the Comptroller has challenged the applicability of the manufacturing exemption to CDM. The period being audited is from August 2006 to August 2007, and liability for that period is potentially covered by an indemnity obligation from CDM's prior owners. CDM may also have liability for periods since 2008, and prospectively, if the Comptroller's challenge is ultimately successful. An audit of the 2008 period has commenced. In April 2013, an independent audit review agreed with the Comptroller's position. While CDM continues to disagree with this position and intends to seek redetermination and other relief, the Partnership is unable to predict the final outcome of this matter.

In addition to the matters discussed above, the Partnership is involved in legal, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies regarding matters arising in the ordinary course of business, none of which are believed to be potentially material to the Partnership at this time.

12. Regency Series A Preferred Units

On September 2, 2009, the Partnership issued 4,371,586 Regency Series A Preferred Units at a price of $18.30 per unit, less issuance costs and a 4% discount of $3 million for net proceeds of $77 million, exclusive of the General Partner's contribution of $2 million. The Regency Series A Preferred Units are convertible to Regency common units under terms described below, and if outstanding, are mandatorily redeemable on September 2, 2029 for $35 million plus all accrued but unpaid distributions thereon (the "Series A Liquidation Value") and accrued interest. The Regency Series A Preferred Units receive fixed quarterly cash distributions of $0.445 per unit which began with the quarter ending March 31, 2010.

Holders may elect to convert Regency Series A Preferred Units to common units at any time. In July 2013, certain holders of Regency Series A Preferred Units exercised their right to convert 2,459,017 Regency Series A Preferred Units into Regency common units. Concurrent with this transaction, the Partnership recognized a $26 million gain in other income and deductions, net, related to the embedded derivative and reclassified $41 million from the Regency Series A Preferred Units into Regency common units. As of December 31, 2013, the remaining Regency Series A Preferred Units were convertible into 2,050,854 Regency common units, and if outstanding, are mandatorily redeemable on September 2, 2029 for $35 million plus all accrued but unpaid distributions and interest thereon. The Regency Series A Preferred Units receive fixed quarterly cash distributions of $0.445 per unit if outstanding on the record dates of the Partnership's common unit distributions.

Distributions on the Regency Series A Preferred Units were accrued for the first two quarters (and not paid in cash) and will result in an increase in the number of Regency common units issuable upon conversion. If on any distribution payment date beginning March 31, 2010, the Partnership (1) fails to pay distributions on the Regency Series A Preferred Units, (2) reduces the distributions on the Regency common units to zero and (3) is prohibited by its material financing agreements from paying cash distributions, such distributions shall automatically accrue and accumulate until paid in cash. If the Partnership has failed to pay cash distributions in full for two quarters (whether or not consecutive) from and including the quarter ended on March 31, 2010, then if the Partnership fails to pay cash distributions on the Regency Series A Preferred Units, all future distributions on the Regency Series A Preferred Units that are accrued rather than being paid in cash by the Partnership will consist of the following: (1) $0.35375 per Regency Series A Preferred Unit per quarter, (2) $0.09125 per Regency Series A Preferred Unit per quarter (the “Common Unit Distribution Amount”), payable solely in common units, and (3) $0.09125 per Regency Series A Preferred Unit per quarter (the “PIK Distribution Additional Amount”), payable solely in common units. The total number of common units payable in connection with the Common Unit Distribution Amount or the PIK Distribution Additional Amount cannot exceed $2 million in any period of 20 consecutive fiscal quarters.

Upon the Partnership’s breach of certain covenants (a “Covenant Default”), the holders of the Regency Series A Preferred Units will be entitled to an increase of $0.1825 per quarterly distribution, payable solely in common units (the “Covenant Default Additional Amount”). All accumulated and unpaid distributions will accrue interest (i) at a rate of 2.432% per quarter, or (ii) if the Partnership has failed to pay all PIK Distribution Additional Amounts or Covenant Default Additional Amounts or any Covenant Default has occurred and is continuing, at a rate of 3.429% per quarter while such failure to pay or such Covenant Default continues.

The Regency Series A Preferred Units are convertible, at the holder’s option, into Regency common units, provided that the holder must request conversion of at least 375,000 Regency Series A Preferred Units. The conversion price will initially be $18.30, subject to adjustment for customary events (such as unit splits). The number of Regency common units issuable is equal to the issue price of the Regency Series A Preferred Units (i.e. $18.30) being converted plus all accrued but unpaid distributions and accrued but unpaid interest thereon (the “Redeemable Face Amount”), divided by the applicable conversion price.

Commencing on September 2, 2014, if at any time the volume-weighted average trading price of the common units over the trailing 20-trading day period (the “VWAP Price”) is less than the then-applicable conversion price, the conversion ratio will be increased to: the quotient of (1) the Redeemable Face Amount on the date that the holder’s conversion notice is delivered, divided by (2) the product of (x) the VWAP Price set forth in the applicable conversion notice and (y) 91%, but will not be less than $10.

Also commencing on September 2, 2014, the Partnership will have the right at any time to convert all or part of the Regency Series A Preferred Units into Regency common units, if (1) the daily volume-weighted average trading price of the common units is greater than 150% of the then-applicable conversion price for 20 out of the trailing 30 trading days, and (2) certain minimum public float and trading volume requirements are satisfied.

In the event of a change of control, the Partnership will be required to make an offer to the holders of the Regency Series A Preferred Units to purchase their Regency Series A Preferred Units for an amount equal to 101% of their Series A Liquidation Value. In addition, in the event of certain business combinations or other transactions involving the Partnership in which the holders of common units receive cash consideration exclusively in exchange for their common units (a “Cash Event”), the Partnership must use commercially reasonable efforts to ensure that the holders of the Regency Series A Preferred Units will be entitled to receive a security issued by the surviving entity in the Cash Event with comparable powers, preferences and rights to the Regency Series A Preferred Units. If the Partnership is unable to ensure that the holders of the Regency Series A Preferred Units will be entitled to receive such a security, then the Partnership will be required to make an offer to the holders of the Regency Series A Preferred Units to purchase their Regency Series A Preferred Units for an amount equal to 120% of their Series A Liquidation Value. If the Partnership enters into any recapitalization, reorganization, consolidation, merger, spin-off that is not a Cash Event, the Partnership will make appropriate provisions to ensure that the holders of the Series A Preferred Units receive a security with comparable powers, preferences and rights to the Regency Series A Preferred Units upon consummation of such transaction. Subsequent to the ETE Acquisition, no unitholder exercised this option.

As of December 31, 2013, the Series A Preferred Units were convertible to 2,050,854 common units.

The following table provides a reconciliation of the beginning and ending balances of the Regency Series A Preferred Units for the year ended December 31, 2013 and 2012:

	Units	Amount
Balance at January 1, 2012	4,371,586	$ 71
Accretion to redemption value	N/A	2
Balance at December 31, 2012	4,371,586	73
Regency Series A Preferred Units converted into common units	(2,459,017)	(41)
Balance at December 31, 2013	1,912,569	$ 32 *

* This amount will be accreted to $35 million plus any accrued but unpaid distributions and interest by deducting amounts from

partners' capital over the remaining periods until the mandatory redemption date of September 2, 2029. Accretion during 2013 was immaterial.

13. Related Party Transactions

As of December 31, 2013 and 2012, details of the Partnership's related party receivables and related party payables were as follows:

	December 31, 2013	December 31, 2012
Related party receivables		
HPC	$ 1	$ 1
ETE and its subsidiaries	25	5
Ranch JV	2	2
Total related party receivables	$ 28	$ 8
Related party payables		
HPC	$ 1	$ 1
ETE and its subsidiaries	68	94
Total related party payables	$ 69	$ 95

Transactions with ETE and its subsidiaries. Under the service agreement with ETE Services Company, LLC ("Services Co."), the Partnership paid Services Co.'s direct expenses for services performed, plus an annual fee of $10 million, and received the benefit of any cost savings recognized for these services. The services agreement has a five year term ending May 26, 2015, subject to earlier termination rights in the event of a change in control, the failure to achieve certain cost savings for the Partnership or upon an event of default. On April 30, 2013, this agreement was amended to provide for a waiver of the $10 million annual fee effective as of May 1, 2013 through and including April 30, 2015 and to clarify the scope and expenses chargeable as direct expenses thereunder.

On April 30, 2013, the Partnership entered into the second amendment (the "Operation and Service Amendment") to the Operation and Service Agreement (the "Operation and Service Agreement"), by and among the Partnership, Energy Transfer Company ("ETC"), the General Partner and RGS. Under the Operation and Service Agreement, ETC performs certain operations, maintenance and related services reasonably required to operate and maintain certain facilities owned by the Partnership, and the Partnership reimburses ETC for actual costs and expenses incurred in connection with the provision of these services based on an annual budget agreed upon by both parties. The Operation and Service Agreement Amendment describes the services that ETC will provide in the future.

The Partnership incurred total service fees related to the agreements described above from ETE and its subsidiaries of $11 million for the year ended December 31, 2013, and $17 million for the years ended December 31, 2012 and 2011.

In conjunction with distributions made by the Partnership to the limited and general partner interests, ETE received cash distributions of $63 million, $62 million and $57 million for the years ended December 31, 2013, 2012 and 2011, respectively.

The General Partner has the right, but not the obligation, to contribute a proportionate amount of capital to the Partnership to maintain its general partner interest. No capital contributions were contributed during the years ended December 31, 2013 and 2012, respectively.

In September 2011, the Partnership purchased a 0.1% interest in MEP from ETP for $1 million in cash.

The Partnership's gathering and processing operations, in the ordinary course of business, sells natural gas and NGL to subsidiaries of ETE and records the revenue in gas sales and NGL sales. The Partnership's contract services operations provides contract compression services to ETP and records revenue in gathering, transportation and other fees on the statement of operations. The Partnership's contract services operations did not sell compression equipment to a subsidiary of ETP for the year ended December 31, 2013, and sold $1 million for the year ended December 31, 2012. As these transactions are between entities under common control, partners' capital was increased, which represented a deemed contribution of the excess sales price over the carrying amounts. The Partnership's contract services operations purchased compression equipment from a subsidiary of ETP for $95 million and $29 million during the years ended December 31, 2013 and 2012, respectively.

Prior to April 30, 2013, Southern Union provided certain administrative services for SUGS that were either based on SUGS's pro-rata share of combined net investment, margin and certain expenses or direct costs incurred by Southern Union on the behalf of SUGS. Southern Union also charged a management and royalty fee to SUGS for certain management support services provided by Southern Union on the behalf of SUGS and for the use of certain Southern Union trademarks, trade names and service marks by SUGS. The amounts were $21 million and $1 million for the period from March 26, 2012 to December 31, 2012. These administrative services were no longer being provided subsequent to the SUGS Acquisition.

Transactions with HPC. Under a Master Services Agreement with HPC, the Partnership operates and provides all employees and services for the operation and management of HPC. For the years ended December 31, 2013, 2012, and 2011, the related party general and administrative expenses reimbursed to the Partnership were $18 million, $20 million, and $17 million, respectively, which is recorded in gathering, transportation and other fees on the statements of operations.

The Partnership's contract services operations provides compression services to HPC and records revenue in gathering, transportation and other fees on the statement of operations. The Partnership also receives transportation services from HPC and records the cost as cost of sales.

Transactions with Lone Star. In 2013, the Partnership entered into a nineteen month agreement to sell NGL to Lone Star for approximately $5 million per month. For the year ended December 31, 2013, the Partnership had recorded $26 million in NGL sales under this contract.

Transactions with Enterprise Product Partners L.P. and its subsidiaries. In January 2012, Enterprise Products Partners L.P. ("EPD") sold a significant portion of its ownership in ETE's common units, and subsequent to that transaction, owns less than 5% of ETE's outstanding common units. As such, EPD is no longer considered a related party. During 2011, EPD owned a portion of ETE's outstanding common units and therefore was considered a related party along with any of its subsidiaries. The Partnership, in the ordinary course of business, sells natural gas and NGLs to subsidiaries of EPD and records the revenue in gas sales and NGL sales. The Partnership also incurs NGL processing fees and transportation fees with subsidiaries of EPD and records these fees as cost of sales.

14. Concentration Risk

The following table provides information about the extent of reliance on major customers and gas suppliers. Total revenues and cost of sales from transactions with an external customer or supplier amounting to 10% or more of revenue or cost of gas and liquids are disclosed below, together with the identity of Regency's reporting segment.

	Regency Reportable Segment	Years Ended December 31,		
		2013	2012	2011
Customer				
Customer A	Gathering and Processing	$ 381	$ 367	$ 366
Customer B	Gathering and Processing	362	451	—
Supplier				
Supplier A	Gathering and Processing	164	171	133
Supplier B	Gathering and Processing	185	—	—

Regency is a party to various commercial netting agreements that allow it and contractual counterparties to net receivable and payable obligations. These agreements are customary and the terms follow standard industry practice. In the opinion of management, these agreements reduce the overall counterparty risk exposure.

15. Regency's Equity-Based Compensation

In December 2011, Regency's unitholders approved the Regency Energy Partners LP 2011 Long-Term Incentive Plan (the "2011 Incentive Plan"), which provides for awards of options to purchase Regency's common units; awards of Regency's restricted units, Regency phantom units and Regency common units; awards of distribution equivalent rights; awards of common unit appreciation rights; and other unit-based awards to employees, directors and consultants of Regency and its affiliates and subsidiaries. The 2011 Incentive Plan will be administered by Regency's Compensation Committee of its board of directors, which may, in its sole discretion, delegate its powers and duties under the 2011 Incentive Plan to the Chief Executive Officer. Up to 3,000,000 of Regency's common units may be granted as awards under the 2011 Incentive Plan, with such amount subject to adjustment as provided for under the terms of the 2011 Incentive Plan.

The 2011 Incentive Plan may be amended or terminated at any time by Regency's board of directors or its Compensation Committee without the consent of any participant or unitholder, including an amendment to increase the number of Regency common units available for awards under the plan; however, any material amendment, such as a change in the types of Regency awards available under the plan, would require the Regency's unitholder approval. Regency's Compensation Committee is also authorized to make adjustments in the terms and conditions of, and the criteria included in awards under the 2011 Incentive Plan in specified circumstances. The 2011 Incentive Plan is effective until December 19, 2021 or, if earlier, the time at which all available units under the 2011 Incentive Plan have been issued to participants or the time of termination of the plan by Regency's board of directors.

Unit-based compensation expense of $7 million, $5 million, and $3 million is recorded in general and administrative expense in the statement of operations for the years ended December 31, 2013, 2012 and 2011, respectively.

Common Unit Options. The fair value of each option award is estimated on the date of grant using the Black-Scholes Option Pricing Model. Upon the exercise of the common unit options, the Partnership intends to settle these obligations with new issues of common units on a net basis. The common unit options activity for the years ended December 31, 2013, 2012, and 2011 is as follows:

2013

Common Unit Options	Units	Weighted Average Exercise Price
Outstanding at the beginning of period	156,550	$ 21.96
Exercised	(14,000)	21.14
Outstanding at end of period	142,550	22.04
Exercisable at the end of the period	142,550	

2012

Common Unit Options	Units	Weighted Average Exercise Price
Outstanding at the beginning of period	156,850	$ 21.99
Forfeited or expired	(300)	23.73
Outstanding at end of period	156,550	21.96
Exercisable at the end of the period	156,550	

2011

Common Unit Options	Units	Weighted Average Exercise Price
Outstanding at the beginning of period	201,950	$ 21.93
Exercised	(38,300)	20.84
Forfeited or expired	(6,800)	26.72
Outstanding at end of period	156,850	21.99
Exercisable at the end of the period	156,850	

The common unit options have an intrinsic value of less than $1 million related to non-vested units with a weighted average contractual term of 2.4 years. Intrinsic value is the closing market price of a unit less the option strike price, multiplied by the number of unit options outstanding as of the end of the period presented. Unit options with an exercise price greater than the end of the period closing market price are excluded.

Phantom Units. In January 2014, the Partnership awarded 668,074 phantom units to senior management and certain key employees. These awards are service condition (time-based) grants that vest 60% at the end of the third year of service and 40% at the end of the fifth year of service.

During 2013, the Partnership awarded 62,360 phantom units to senior management and certain key employees. These awards are service condition (time-based) grants that generally vest 60% at the end of the third year of service and 40% at the end of the fifth year of service. Distributions on the phantom units will be paid concurrent with the Partnership's distribution for common units.

In December 2012, the Partnership awarded 495,375 phantom units to senior management and certain key employees. These awards are service condition (time-based) grants that vest 60% at the end of the third year of service and 40% at the end of the fifth year of service. Also during 2012, 8,250 phantom units were awarded to senior management and key employees as service condition (time-based) grants that generally vest ratably over the next 5 years. Distributions on the phantom units (including non-vested units) will be paid concurrent with the Partnership's distribution for common units.

During 2011, the Partnership awarded 596,320 phantom units to senior management and certain key employees. These awards are service condition (time-based) grants that generally vest ratably over the next 5 years. Distributions on the phantom units (including non-vested units) will be paid concurrent with the Partnership's distribution for common units.

The following table presents phantom unit activity for the years ended December 31, 2013, 2012 and 2011:

2013			
Phantom Units	**Units**		**Weighted Average Grant Date Fair Value**
Outstanding at the beginning of the period	1,231,342	$	23.22
Service condition grants	62,360		25.44
Vested service condition	(231,163)		24.80
Forfeited service condition	(35,900)		23.22
Forfeited market condition	(44,397)		19.52
Total outstanding at end of period	982,242		23.16

2012			
Phantom Units	**Units**		**Weighted Average Grant Date Fair Value**
Outstanding at the beginning of the period	1,086,393	$	24.51
Service condition grants	503,625		21.39
Vested service condition	(223,258)		24.71
Vested market condition	(10,200)		19.52
Forfeited service condition	(120,868)		24.85
Forfeited market condition	(4,350)		19.52
Total outstanding at end of period	1,231,342		23.22

2011			
Phantom Units	**Units**		**Weighted Average Grant Date Fair Value**
Outstanding at the beginning of the period	742,517	$	23.61
Service condition grants	596,320		24.55
Vested service condition	(142,520)		24.73
Vested market condition	(8,550)		19.52
Forfeited service condition	(88,474)		24.99
Forfeited market condition	(12,900)		19.52
Total outstanding at end of period	1,086,393		24.51

The Partnership expects to recognize $19 million of unit-based compensation expense related to non-vested phantom units over a period of 3.3 years.

6. ETE GP ACQUIRER LLC AND SUBSIDIARIES CONSOLIDATED FINANCIAL STATEMENTS

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Member
ETE GP Acquirer LLC

We have audited the accompanying consolidated balance sheets of ETE GP Acquirer LLC (a Delaware limited liability company) and subsidiaries (the “Company”) as of December 31, 2013 and 2012, and the related consolidated statements of operations, comprehensive income, cash flows, and member’s equity and noncontrolling interest for each of the three years in the period ended December 31, 2013. These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on these financial statements based on our audits. We did not audit the financial statements of Midcontinent Express Pipeline LLC, a 50 percent owned investee company, the Company’s investment in which is accounted for under the equity method of accounting. The Company’s investment in Midcontinent Express Pipeline LLC as of December 31, 2013 and 2012 was $548 million and $581 million, respectively, and its equity in the earnings of Midcontinent Express Pipeline LLC was $39 million, $42 million, and $43 million, respectively, for each of the three years in the period ended December 31, 2013. Those statements were audited by other auditors, whose reports has been furnished to us, and our opinion, insofar as it relates to the amounts included for Midcontinent Express Pipeline LLC, is based solely on the reports 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. We were not engaged to perform an audit of the Company’s internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company’s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, 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 reports of the other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audits and the reports of the other auditors, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of ETE GP Acquirer LLC and subsidiaries as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1, the accompanying consolidated financial statements have been adjusted to reflect the acquisition of an entity under common control, which has been accounted for in a manner similar to a pooling of interests.

/s/ GRANT THORNTON LLP

Dallas, Texas
February 27, 2014

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ETE GP Acquirer LLC

Consolidated Balance Sheets
(in millions)

	December 31, 2013	December 31, 2012
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 19	$ 53
Trade accounts receivable	292	222
Related party receivables	28	8
Inventories	42	27
Other current assets	19	30
Total current assets	400	340
Property, Plant and Equipment:		
Gathering and transmission systems	1,671	1,308
Compression equipment	1,627	1,326
Gas plants and buildings	825	568
Other property, plant and equipment	414	377
Construction-in-progress	513	507
Total property, plant and equipment	5,050	4,086
Less accumulated depreciation	(632)	(400)
Property, plant and equipment, net	4,418	3,686
Other Assets:		
Investments in unconsolidated affiliates	2,097	2,214
Other, net of accumulated amortization of debt issuance costs of $24 and $17	57	43
Total other assets	2,154	2,257
Intangible Assets and Goodwill:		
Intangible assets, net of accumulated amortization of $107 and $77	682	712
Goodwill	1,128	1,128
Total intangible assets and goodwill	1,810	1,840
TOTAL ASSETS	$ 8,782	$ 8,123
LIABILITIES & MEMBER’S EQUITY AND NONCONTROLLING INTEREST		
Current Liabilities:		
Drafts payable	$ 26	$ 10
Trade accounts payable	291	255
Related party payables	69	95
Accrued interest	38	30
Other current liabilities	51	99
Total current liabilities	475	489
Long-term derivative liabilities	19	25
Other long-term liabilities	30	39
Long-term debt, net	3,310	2,157
Commitments and contingencies		
Regency’s Series A Preferred Units, redemption amount of $38 and $85	32	73
Member’s Equity and Noncontrolling Interest:		
Member’s equity	782	326
Predecessor equity	—	1,733
Total member’s equity	782	2,059
Noncontrolling interest	4,134	3,281
Total member’s equity and noncontrolling interest	4,916	5,340
TOTAL LIABILITIES AND MEMBER’S EQUITY AND NONCONTROLLING INTEREST	$ 8,782	$ 8,123

See accompanying notes to consolidated financial statements

ETE GP Acquirer LLC

Consolidated Statements of Operations
(in millions)

	Years Ended December 31,		
	2013	2012	2011
REVENUES			
Gas sales, including related party amounts of $71, $42, and $23	$ 826	$ 508	$ 456
NGL sales, including related party amounts of $81, $28, and $365	1,053	991	603
Gathering, transportation and other fees, including related party amounts of $26, $29, and $24	545	401	351
Net realized and unrealized (loss) gain from derivatives	(8)	23	(19)
Other, including related party amounts of $-, $1, and $10	105	77	43
Total revenues	2,521	2,000	1,434
OPERATING COSTS AND EXPENSES			
Cost of sales, including related party amounts of $56, $35, and $22	1,793	1,387	1,013
Operation and maintenance	296	228	147
General and administrative, including related party amounts of $11, $15, and $17	88	100	67
Loss (gain) on asset sales, net	2	3	(2)
Depreciation and amortization	287	252	169
Total operating costs and expenses	2,466	1,970	1,394
OPERATING INCOME	55	30	40
Income from unconsolidated affiliates	135	105	120
Interest expense, net	(164)	(122)	(103)
Loss on debt refinancing, net	(7)	(8)	—
Other income and deductions, net	7	29	17
INCOME BEFORE INCOME TAXES	26	34	74
Income tax benefit	(1)	—	—
NET INCOME	$ 27	$ 34	$ 74
Net income attributable to noncontrolling interest	(16)	(25)	(67)
NET INCOME ATTRIBUTABLE TO ETE GP ACQUIRER LLC	$ 11	$ 9	$ 7

See accompanying notes to consolidated financial statements

ETE GP Acquirer LLC

Consolidated Statements of Comprehensive Income
(in millions)

	Years Ended December 31,		
	2013	2012	2011
Net income	$ 27	$ 34	$ 74
Other comprehensive income:			
Net cash flow hedge amounts reclassified to earnings	—	6	19
Change in fair value of cash flow hedges	—	(4)	(13)
Total other comprehensive income	$ —	$ 2	$ 6
Comprehensive income	$ 27	$ 36	$ 80
Comprehensive income attributable to noncontrolling interest	16	25	67
Comprehensive income attributable to ETE GP Acquirer LLC	$ 11	$ 11	$ 13

See accompanying notes to consolidated financial statements

ETE GP Acquirer LLC

Consolidated Statements of Member's Equity and Noncontrolling Interest
(in millions)

	Member's Equity	AOCI	Predecessor Equity	Noncontrolling Interest	Total
Balance—December 31, 2010	$ 333	$ (11)	$ —	$ 2,972	$ 3,294
Regency common unit offerings, net of costs	—	—	—	436	436
Regency unit-based compensation expenses	—	—	—	3	3
Distributions to partners and noncontrolling interests	(10)	—	—	(264)	(274)
Net income	7	—	—	67	74
Distributions to Regency Series A Preferred Units	—	—	—	(8)	(8)
Net cash flow hedge amounts reclassified to earnings	—	19	—	—	19
Net change in fair value of cash flow hedges	—	(13)	—	—	(13)
Balance—December 31, 2011	$ 330	$ (5)	$ —	$ 3,206	$ 3,531
Regency common unit offerings, net of costs	—	—	—	312	312
Regency common units issued under LTIP, net of forfeitures and tax withholding	—	—	—	(1)	(1)
Regency unit-based compensation expenses	—	—	—	5	5
Distributions to partners and noncontrolling interests	(13)	—	—	(309)	(322)
Net income	9	—	(14)	39	34
Contributions from noncontrolling interest	—	—	—	42	42
Distributions to Regency Series A Preferred Units	—	—	—	(8)	(8)
Accretion of Series A Preferred Units	—	—	—	(2)	(2)
Net cash flow hedge amounts reclassified to earnings	—	5	—	—	5
Contribution of net investment to unitholders	—	(3)	1,747	—	1,744
Balance—December 31, 2012	$ 326	$ (3)	$ 1,733	$ 3,284	$ 5,340
Contribution of net investment to Regency	1,925	3	(1,928)	—	—
Regency issuance of common units in connection with the SUGS Acquisition, net of costs	(819)	—	—	819	—
Regency issuance of Regency Class F common units in connection with the SUGS Acquisition, net of costs	(142)	—	—	142	—
Contribution of assets between entities under common control below historical cost	(504)	—	231	—	(273)
Regency common unit offerings, net of costs	—	—	—	149	149
Conversion of Regency Series A Preferred Units for common units	—	—	—	41	41
Regency unit-based compensation expenses	—	—	—	7	7
Distributions to partners, noncontrolling interests and subsidiary's unvested unit awards	(15)	—	—	(371)	(386)
Contributions from noncontrolling interest	—	—	—	17	17
Net income	11	—	(36)	52	27
Distributions to Regency Series A Preferred Units	—	—	—	(6)	(6)
Balance—December 31, 2013	$ 782	$ —	$ —	$ 4,134	$ 4,916

See accompanying notes to consolidated financial statements

ETE GP Acquirer LLC

Consolidated Statements of Cash Flows
(in millions)

	Years Ended December 31,		
	2013	2012	2011
OPERATING ACTIVITIES			
Net income	$ 27	$ 34	$ 74
Reconciliation of net income to net cash flows provided by operating activities:			
Depreciation and amortization, including debt issuance cost amortization and bond premium write-off and amortization	293	259	175
Income from unconsolidated affiliates	(135)	(105)	(120)
Derivative valuation changes	6	(12)	(21)
Loss (gain) on asset sales, net	2	3	(2)
Regency unit-based compensation expenses	7	5	3
Cash flow changes in current assets and liabilities:			
Trade accounts receivable and related party receivables	(96)	—	(8)
Other current assets and other current liabilities	(54)	10	11
Trade accounts payable, related party payables and deferred revenues	119	18	23
Distributions of earnings received from unconsolidated affiliates	142	121	119
Cash flow changes in other assets and liabilities	125	(9)	—
Net cash flows provided by operating activities	436	324	254
INVESTING ACTIVITIES			
Capital expenditures	(1,034)	(560)	(406)
Capital contributions to unconsolidated affiliates	(148)	(356)	(53)
Distributions in excess of earnings of unconsolidated affiliates	249	83	74
Acquisition of investment in unconsolidated affiliates, net of cash received	—	—	(594)
Acquisitions, net of cash received	(475)	—	—
Proceeds from asset sales	15	26	24
Net cash flows used in investing activities	(1,393)	(807)	(955)
FINANCING ACTIVITIES			
Borrowings (repayments) under revolving credit facility, net	318	(140)	47
Proceeds from issuance of senior notes	1,000	700	500
Redemptions of senior notes	(163)	(88)	—
Debt issuance costs	(24)	(15)	(10)
Distributions to non-controlling interest and subsidiary distributions on unvested unit awards	(371)	(309)	(264)
Partner distributions	(15)	(13)	(10)
Contributions from noncontrolling interest	17	42	—
Contributions from previous parent	—	51	—
Drafts payable	18	4	2
Subsidiary common units issued under LTIP, net of forfeitures and tax withholding	—	(1)	—
Proceeds from Regency issuance of common units, net of issuance costs	149	312	436
Distributions to Regency Series A Preferred Units	(6)	(8)	(8)
Net cash flows provided by financing activities	923	535	693
Net change in cash and cash equivalents	(34)	52	(8)
Cash and cash equivalents at beginning of period	53	1	9
Cash and cash equivalents at end of period	$ 19	$ 53	$ 1
Supplemental cash flow information:			
Accrued capital expenditures	$ 60	$ 136	$ 24
Issuance of Class F and common units in connection with SUGS Acquisition	961	—	—
Interest paid, net of amounts capitalized	146	112	83
Income taxes paid	—	—	2
Accrued capital contribution to unconsolidated affiliate	13	23	—

See accompanying notes to consolidated financial statements

ETE GP Acquirer LLC
Notes to Consolidated Financial Statements
(Tabular dollar amounts are in millions)

1. Organization and Basis of Presentation

Organization of ETE GP Acquirer LLC. ETE GP Acquirer LLC ("GP Acquirer") is a wholly-owned subsidiary of Energy Transfer Equity, L.P. ("ETE") and owns 99.999% of the limited partner interest in Regency GP LP and 100% membership interest in Regency GP LLC, an entity that owns the 0.001% general partner interest in Regency GP LP.

Organization of Regency GP LP. Regency GP LP (the "General Partner") is the general partner of Regency Energy Partners LP. The General Partner owns a 1.3% general partner interest and the incentive distribution rights of Regency Energy Partners LP.

Organization of Regency Energy Partners LP. Regency Energy Partners LP and its subsidiaries ("Regency" or the "Partnership") are engaged in the business of gathering, processing and transporting natural gas and natural gas liquids ("NGLs") as well as providing contract compression services.

SUGS Acquisition. In April 2013, the Partnership acquired Southern Union Gas Services ("SUGS") from Southern Union Company ("Southern Union"), a wholly-owned subsidiary of Holdco, for $1.5 billion (the "SUGS Acquisition"). The Partnership financed the acquisition by issuing to Southern Union 31,372,419 of Regency common units and 6,274,483 Regency Class F common units. The Regency Class F common units are not entitled to participate in the Partnership's distributions for twenty-four months post-transaction closing. The remaining $600 million, less $107 million of closing adjustments, was paid in cash. In addition, ETE agreed to forgo IDR payments on the Partnership common units issued with this transaction for the twenty-four months post-transaction closing and to suspend the $10 million annual management fee paid by the Partnership for two years post-transaction close.

The Regency common units and Regency Class F common units related to the SUGS Acquisition were issued in a private placement conducted in accordance with the exemption from registration requirements of the Securities Act of 1933, as amended under Section 4(2) thereof. The Regency Class F common units will convert into common units on a one-for-one basis in May 2015.

The cash portion of the SUGS Acquisition was funded from the net proceeds of $600 million of senior notes issued by the Partnership on April 30, 2013 in a private placement. In December 2013, these senior notes were exchanged for senior notes that are substantially identical, except that the exchange senior notes are registered under federal securities law and do not have any transfer restrictions. In January 2014, Panhandle Eastern Pipe Line Company, LP ("PEPL") entered into an agreement and plan of merger with Southern Union and PEPL Holdings, LLC ("PEPL Holdings"), pursuant to which each of Southern Union and PEPL Holdings were merged with and into PEPL, with PEPL as the surviving entity. In connection with this merger, PEPL assumed the guarantee of collection with respect to the payment of the principal amounts of the senior notes issued.

The Partnership accounted for the SUGS Acquisition in a manner similar to the pooling of interest method of accounting, as it was a transaction between commonly controlled entities. Under this method of accounting, the Partnership reflected historical balance sheet data for the Partnership and SUGS instead of reflecting the fair market value of SUGS assets and liabilities from the date of acquisition forward. The Partnership retrospectively adjusted its financial statements to include the balances and operations of SUGS from March 26, 2012 (the date upon which common control began).

The assets acquired and liabilities assumed in the SUGS Acquisition were as follows:

	April 30, 2013
Current assets	$ 113
Property, plant and equipment, net	1,608
Goodwill	337
Other non-current assets	1
Total assets acquired	$ 2,059
Less:	
Current liabilities	(93)
Non-current liabilities	(36)
Net assets acquired	$ 1,930

The following table presents the revenues and net income for the previously separate entities and combined amounts presented herein:

	Years Ended December 31,	
	2013	2012
Revenues:		
Partnership	$ 2,253	$ 1,339
SUGS (1)	268	661
Combined	$ 2,521	$ 2,000
Net income (loss):		
Partnership	$ 63	$ 48
SUGS (1)	(36)	(14)
Combined	$ 27	$ 34

(1) Combined amounts attributable to SUGS include the period from March 26, 2012 to December 31, 2012 for the year ended December 31, 2012, and the period from January 1, 2013 to April 30, 2013 for the year ended December 31, 2013. Subsequent to the closing of the SUGS Acquisition on April 30, 2013, the results of SUGS were attributable to the Partnership.

Basis of presentation. The consolidated financial statements of the GP Acquirer have been prepared in accordance with GAAP and include the accounts of all controlled subsidiaries after the elimination of all intercompany accounts and transactions. Certain prior year numbers have been conformed to the current year presentation. Subsequent events have been evaluated through February 27, 2014, the date the financial statements were issued.

2. Summary of Significant Accounting Policies

Use of Estimates. These consolidated financial statements have been prepared in conformity with GAAP, which includes the use of estimates and assumptions by management that affect the reported amounts of assets, liabilities, revenues, expenses and disclosure of contingent assets and liabilities that exist at the date of the financial statements. Although these estimates are based on management's available knowledge of current and expected future events, actual results could be different from those estimates.

Common Control Transactions. Entities and assets acquired from ETE and its affiliates are accounted for as common control transactions whereby the net assets acquired are combined with the Partnership's net assets at their historical amounts. If consideration transferred differs from the carrying value of the net assets acquired, the excess or deficiency is treated as a capital transaction similar to a dividend or capital contribution. To the extent that such transactions require prior periods to be recast, historical net equity amounts prior to the transaction date are reflected in predecessor equity.

Cash and Cash Equivalents. Cash and cash equivalents include temporary cash investments with original maturities of three months or less.

Equity Method Investments. The equity method of accounting is used to account for the Partnership's interest in investments of greater than 20% voting interest or where the Partnership exerts significant influence over an investee but lacks control over the investee.

Inventories. Inventories are valued at the lower of cost or market and include materials and parts primarily utilized by the Contract Services segment.

Property, Plant and Equipment. Property, plant and equipment is recorded at historical cost of construction or, upon acquisition, the fair value of the assets acquired. Gains or losses on sales or retirements of assets are included in operating income unless the disposition is treated as discontinued operations. Natural gas and NGLs used to maintain pipeline minimum pressures is and classified as property, plant and equipment. Financing costs associated with the construction of larger assets requiring ongoing efforts over a period of time are capitalized. For the years ended December 31, 2013, 2012 and 2011, the Partnership capitalized interest of $2 million, $1 million and $1 million, respectively. The costs of maintenance and repairs, which are not significant improvements, are expensed when incurred. Expenditures to extend the useful lives of the assets are capitalized.

Depreciation expense related to property, plant and equipment was $258 million, $219 million, and $138 million for the years ended December 31, 2013, 2012 and 2011, respectively. In March 2012, the Partnership recorded a $7 million "out-of-period" adjustment to depreciation expense to correct the estimated useful lives of certain assets to comply with its policy.

Depreciation of property, plant and equipment is recorded on a straight-line basis over the following estimated useful lives:

Functional Class of Property	Useful Lives (Years)
Gathering and Transmission Systems	10 - 50
Compression Equipment	2 - 30
Gas Plants and Buildings	5 - 35
Other property, plant and equipment	3 - 15

Intangible Assets. As of December 31, 2013, intangible assets consisted of trade names and customer relations, and are amortized on a straight line basis over their estimated useful lives, which is the period over which the assets are expected to contribute directly or indirectly to the Partnership’s future cash flows. The estimated useful lives range from 20 to 30 years.

The Partnership assesses long-lived assets, including property, plant and equipment and intangible assets, for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability is assessed by comparing the carrying amount of an asset to undiscounted future net cash flows expected to be generated by the asset. If such assets are considered to be impaired, the impairment to be recognized is measured as the amount by which the carrying amounts exceed the fair value of the assets. The Partnership did not record any impairment in 2013, 2012 or 2011.

Goodwill. Goodwill represents the excess of the purchase price over the fair value of identifiable net assets acquired in a business combination. Goodwill is not amortized, but is tested for impairment annually based on the carrying values as of November 30 or December 31 depending upon the reporting unit, or more frequently if impairment indicators arise that suggest the carrying value of goodwill may not be recovered. The Partnership has the option to first assess qualitative factors to determine whether it is more likely than not that the fair value of the reporting unit is less than its carrying amount as a basis for determining whether further impairment testing is necessary. Impairment is indicated when the carrying amount of a reporting unit exceeds its fair value. To estimate the fair value of the reporting units, the Partnership makes estimates and judgments about future cash flows, as well as revenues, cost of sales, operating expenses, capital expenditures and net working capital based on assumptions that are consistent with the Partnership’s most recent forecast. At the time it is determined that an impairment has occurred, the carrying value of the goodwill is written down to its fair value. The Partnership did not record any impairment in 2013, 2012 or 2011.

Other Assets, net. Other assets, net primarily consists of debt issuance costs, which are capitalized and amortized to interest expense, net over the life of the related debt.

Gas Imbalances. Quantities of natural gas or NGLs over-delivered or under-delivered related to imbalance agreements are recorded monthly as other current assets or other current liabilities using then current market prices or the weighted average prices of natural gas or NGLs at the plant or system pursuant to imbalance agreements for which settlement prices are not contractually established. Within certain volumetric limits determined at the sole discretion of the creditor, these imbalances are generally settled by deliveries of natural gas. Imbalance receivables and payables as of December 31, 2013 and 2012 were immaterial.

Asset Retirement Obligations. Legal obligations associated with the retirement of long-lived assets are recorded at fair value at the time the obligations are incurred, if a reasonable estimate of fair value can be made. Present value techniques are used which reflect assumptions such as removal and remediation costs, inflation, and profit margins that third parties would demand to settle the amount of the future obligation. The Partnership does not include a market risk premium for unforeseeable circumstances in its fair value estimates because such a premium cannot be reliably estimated. Upon initial recognition of the liability, costs are capitalized as a part of the long-lived asset and allocated to expense over the useful life of the related asset. The liability is accreted to its present value each period with accretion being recorded to operating expense with a corresponding increase in the carrying amount of the liability. The ARO assets and liabilities were immaterial as of December 31, 2013.

Environmental. The Partnership's operations are subject to federal, state and local laws and rules and regulations regarding water quality, hazardous and solid waste management, air quality control and other environmental matters. These laws, rules and regulations require the Partnership to conduct its operations in a specified manner and to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections and other approvals. Failure to comply with applicable environmental laws, rules and regulations may expose the Partnership to significant fines, penalties and/or interruptions in operations. The Partnership's environmental policies and procedures are designed to achieve compliance with such applicable laws and regulations. These evolving laws and regulations and claims for damages to property, employees, other persons and the environment resulting from current or past operations may result in significant expenditures and liabilities in the future.

Predecessor Equity. Predecessor equity included on the consolidated statement of partners' capital and noncontrolling interest represents SUGS member's capital prior to the acquisition date (April 30, 2013).

Revenue Recognition. The Partnership earns revenue from (i) domestic sales of natural gas, NGLs and condensate, (ii) natural gas gathering, processing and transportation, and (iii) contract compression and treating services. Revenue associated with sales of natural gas, NGLs and condensate are recognized when title passes to the customer, which is when the risk of ownership passes to the purchaser and physical delivery occurs. Revenue associated with transportation and processing fees are recognized when the service is provided. For contract compression and contract treating services, revenue is recognized when the service is performed. For gathering and processing services, the Partnership receives either fees or commodities from natural gas producers depending on the type of contract. Commodities received are in turn sold and recognized as revenue in accordance with the criteria outlined above. Under the percentage-of-proceeds contract type, the Partnership is paid for its services by keeping a percentage of the NGLs produced and a percentage of the residue gas resulting from processing the natural gas. Under the percentage-of-index contract type, the Partnership earns revenue by purchasing wellhead natural gas at a percentage of the index price and selling processed natural gas and NGLs at a price approximating the index price to third parties. The Partnership generally reports revenue gross in the consolidated statements of operations when it acts as the principal, takes title to the product, and incurs the risks and rewards of ownership. Revenue for fee-based arrangements is presented net, because the Partnership takes the role of an agent for the producers. Allowance for doubtful accounts is determined based on historical write-off experience and specific identification.

Derivative Instruments. The Partnership's net income and cash flows are subject to volatility stemming from changes in market prices such as natural gas prices, NGLs prices, processing margins and interest rates. The Partnership uses product-specific swaps to create offsetting positions to specific commodity price exposures, and uses interest rate swap contracts to create offsetting positions to specific interest rate exposures. Derivative financial instruments are recorded on the balance sheet at their fair value based on their settlement date. The Partnership employs derivative financial instruments in connection with an underlying asset, liability and/or anticipated transaction and not for speculative purposes. Furthermore, the Partnership regularly assesses the creditworthiness of counterparties to manage the risk of default. Derivative financial instruments qualifying for hedge accounting treatment may be designated by the Partnership as cash flow hedges. The Partnership enters into cash flow hedges to hedge the variability in cash flows related to a forecasted transaction. At inception, the Partnership formally documents the relationship between the hedging instrument and the hedged item, the risk management objectives, and the methods used for assessing and testing correlation and hedge effectiveness. The Partnership also assesses, both at the inception of the hedge and on an on-going basis, whether the derivatives are highly effective in offsetting changes in cash flows of the hedged item. If the Partnership determines that a derivative is no longer highly effective as a hedge, it would discontinues hedge accounting prospectively by including changes in the fair value of the derivative in current earnings. For cash flow hedges, changes in the derivative fair values, to the extent that the hedges are effective, are recorded as a component of accumulated other comprehensive income (loss) until the hedged transactions occur and are recognized in earnings. Any ineffective portion of a cash flow hedge's change in value is recognized immediately in earnings. In the statement of cash flows, the effects of settlements of derivative instruments are classified consistent with the related hedged transactions.

Benefits. The Partnership provides medical, dental, and other healthcare benefits to employees. The total amount incurred by the Partnership for the years ended December 31, 2013, 2012 and 2011, was $9 million, $9 million and $6 million, respectively, in operation and maintenance and general and administrative expenses, as appropriate. The Partnership also provides a matching contribution to its employee's 401(k) accounts. Effective January 1, 2011, the Partnership's 401(k) plan merged with and into that of Energy Transfer Partners ("ETP"). As a result of the merger, the Partnership's matching contributions that had not yet fully vested became fully vested. All future matching contributions from the Partnership to the employee 401(k) accounts vest immediately. In addition, SUGS maintained a separate defined contribution plan during March 26, 2012 to December 31, 2012. The total amount of matching contributions for the years ended December 31, 2013, 2012 and 2011 was $7 million, $4 million and $3 million, respectively, and were recorded in operation and maintenance and general and administrative expenses as appropriate. The Partnership has no pension obligations or other post-employment benefits. Beginning January 1, 2013, the Partnership provides a 3% profit sharing contribution to employee 401(k) accounts for all employees with base compensation below a specified threshold. The contribution is in addition to the 401(k) matching contribution and employees become vested based on years of service.

Income Taxes. The Partnership is generally not subject to income taxes, except as discussed below, because its income is taxed directly to its partners. The Partnership is subject to the gross margins tax enacted by the state of Texas. The Partnership has two wholly-owned subsidiaries that are subject to income tax and provides for deferred income taxes using the asset and liability method. Accordingly, deferred taxes are recorded for differences between the tax and book basis that will reverse in future periods. The Partnership has deferred tax liabilities of $22 million as of December 31, 2013 and 2012 related to the difference between the book and tax basis of property, plant and equipment and intangible assets and they are included in other long-term liabilities in the accompanying consolidated balance sheets. The Partnership follows the guidance for uncertainties in income taxes where a liability for an unrecognized tax benefit is recorded for a tax position that does not meet the "more likely than not" criteria. The Partnership has not recorded any uncertain tax positions meeting the more likely than not criteria as of December 31, 2013 and 2012. The Partnership recognized an immaterial amount for current federal income tax expense and deferred income tax benefit for the years ended December 31, 2013, 2012, and 2011.

Although the SUGS operations were included in the Southern Union consolidated federal income tax return prior to the SUGS Acquisition, following their acquisition by the Partnership, SUGS's operations are now treated as a pass-through entity. Therefore, other than one wholly-owned subsidiary, SUGS's historical operations exclude income taxes for all periods presented.

Effective with the Partnership's acquisition of SUGS on April 30, 2013, SUGS is generally no longer subject to federal income taxes and subject only to gross margins tax in the state of Texas. Substantially all previously recorded current and deferred tax liabilities were settled with Southern Union, along with all other intercompany receivables and payables at the date of acquisition.

The IRS commenced audits of our 2007 and 2008 federal income tax returns on January 27, 2010. The IRS has now completed its audit of these returns and proposed certain adjustments. The Partnership filed a protest with the IRS to initiate the appeals process and appeal certain of these adjustments. Until this matter is fully resolved, it is not known whether any amounts ultimately recorded would be material, or how such adjustments would affect unitholders. The statute of limitations for these audits has been extended to December 31, 2014. In January 2014, the Partnership settled the 2007 through 2009 tax returns audit for a wholly-owned subsidiary for an immaterial amount.

Equity-Based Compensation. The Partnership accounts for equity-based compensation by recognizing the grant-date fair value of awards into expense as they are earned, using an estimated forfeiture rate. The forfeiture rate assumption is reviewed annually to determine whether any adjustments to expense are required.

3. Regency Unit Activity Reflected in Noncontrolling Interest

Regency Units Activity. The changes in Regency's common and Class F units were as follows:

	Regency Common Units	Regency Class F Units
Balance - December 31, 2010	137,281,336	—
Regency common unit offerings, net of costs	20,000,001	—
Regency's issuance of common units under LTIP, net of forfeitures and tax withholding	156,271	—
Balance - December 31, 2011	157,437,608	—
Regency common unit offerings, net of costs	12,650,000	—
Regency's issuance of common units under an equity distribution agreement, net of costs	691,129	—
Regency's issuance of common units under LTIP, net of forfeitures and tax withholding	172,720	—
Balance - December 31, 2012	170,951,457	—
Regency's issuance of common units under LTIP, net of forfeitures and tax withholding	184,995	—
Regency's issuance of common units under an equity distribution agreement, net of costs	5,712,138	—
Conversion of Regency Series A preferred units for Regency common units	2,629,223	—
Regency's Issuance of common units and Class F common units in connection with SUGS Acquisition	31,372,419 (1)	6,274,483 (2)
Balance - December 31, 2013	210,850,232	6,274,483

(1) ETE has agreed to forgo IDR payments on the Regency common units issued with the SUGS Acquisition for twenty-four months post-transaction closing.
(2) Regency's Class F common units are not entitled to participate in Regency's distributions or earnings for twenty-four months post-transaction closing.

Equity Distribution Agreement. In June 2012, Regency entered into an Equity Distribution Agreement with Citi under which Regency may offer and sell its common units, representing limited partner interests, having an aggregate offering price of up to $200 million, from time to time through Citi, as sales agent for Regency. Sales of these units, if any, made from time to time under the Equity Distribution Agreement will be made by means of ordinary brokers' transactions on the New York Stock Exchange at market prices, in block transactions, or as otherwise agreed upon by Regency and Citi. Regency may also sell its common units to Citi as principal for its own account at a price agreed upon at the time of sale. Any sale of Regency common units to Citi as principal would be pursuant to the terms of a separate agreement between Regency and Citi. Regency intends to use the net proceeds from the sale of these units for general partnership purposes. For the years ended December 31, 2013 and 2012, Regency received net proceeds of $149 million and $15 million, respectively, from Regency units issued pursuant to this Equity Distribution Agreement. As of December 31, 2013, $34 million remains available to be issued under this agreement.

Public Common Unit Offerings. In March 2012, Regency issued 12,650,000 of its common units representing limited partner interests in a public offering at a price of $24.47 per Regency common unit, resulting in net proceeds of $297 million. In May 2012, Regency used the net proceeds from this offering to redeem 35%, or $88 million, in aggregate principal amounts of its outstanding senior notes due 2016; pay related premium, expenses and accrued interest; and repay outstanding borrowings under its revolving credit facility. In August 2010, Regency sold 17,537,500 of its common units and received $408 million in proceeds, inclusive of the General Partner's proportionate capital contribution. In October 2011, Regency issued 11,500,000 of its common units representing limited partnership interests in a public offering at a price of $20.92 per Regency common unit, resulting in net proceeds of $232 million which were used to repay outstanding borrowings under its revolving credit facility.

Private Common Unit Offerings. In May 2011, Regency sold 8,500,001 of its common units representing limited partnership interests resulting in net proceeds of $204 million, to partially fund its capital contribution to Lone Star. These units were issued in a private placement conducted in accordance with the exemption from the registration requirements of the Securities Act of 1933, as amended, under section 4(2) thereof. These units were subsequently registered with the SEC.

Beneficial Conversion Feature. Regency issued 6,274,483 Regency Class F common units in connection with the SUGS Acquisition. At the commitment date (February 27, 2013), the sales price of $23.91 per unit represented a $2.19 per unit discount from the fair value of the Regency's common units as of April 30, 2013. The Class F common units are convertible to common units on a one-for-one basis on May 8, 2015.

Noncontrolling Interest. Regency operates Edwards Lime Gathering LLC and its operating subsidiaries ("ELG"), a gas gathering joint venture in South Texas in which other third party companies own a 40% interest, which is reflected on Regency's consolidated balance sheet as noncontrolling interest.

Distributions. The partnership agreement requires the distribution of all of the Partnership's Available Cash (defined below) within 45 days after the end of each quarter to unitholders of record on the applicable record date, as determined by the General Partner.

Available Cash. Available Cash, for any quarter, generally consists of all cash and cash equivalents on hand at the end of that quarter less the amount of cash reserves established by the general partner to: (i) provide for the proper conduct of the Partnership's business; (ii) comply with applicable law, any debt instruments or other agreements; or (iii) provide funds for distributions to the unitholders and to the General Partner for any one or more of the next four quarters and plus, all cash on hand on that date of determination of available cash for the quarter resulting from working capital borrowings made after the end of the quarter for which the determination is being made.

General Partner Interest and Incentive Distribution Rights. The General Partner is entitled to its proportionate share of all quarterly distributions that Regency makes prior to its liquidation. The General Partner has the right, but not the obligation, to contribute a proportionate amount of capital to the Partnership to maintain its current general partner interest. The General Partner's initial 2% interest in these distributions has been reduced since the Partnership has issued additional units and the General Partner has not contributed a proportionate amount of capital to the Partnership to maintain its General Partner interest. The General Partner ownership interest as of December 31, 2013 was 1.3%. This General Partner interest is represented by 2,834,381 equivalent units as of December 31, 2013.

The IDRs held by the General Partner entitle it to receive an increasing share of Available Cash when pre-defined distribution targets are achieved. The General Partner's IDRs are not reduced if the Partnership issues additional units in the future and the general partner does not contribute a proportionate amount of capital to the Partnership to maintain its general partner interest.

In connection with the SUGS Acquisition, ETE agreed to forgo IDR payments on Regency common units issued with this transaction for the twenty-four months post-transaction closing.

Distributions. Regency made the following cash distributions per unit during the years ended December 31, 2013 and 2012:

Distribution Date	Cash Distribution (per common unit)
November 14, 2013	$ 0.470
August 14, 2013	0.465
May 13, 2013	0.460
February 14, 2013	0.460
November 14, 2012	$ 0.460
August 14, 2012	0.460
May 14, 2012	0.460
February 13, 2012	0.460

Regency paid a cash distribution of $0.475 per common unit on February 14, 2014.

4. Acquisitions and Dispositions

2013

SUGS Acquisition. The SUGS Acquisition is discussed in footnote 1 - Organization and Basis of Presentation.

PVR Acquisition. In October 2013, the Partnership announced that it entered into a merger agreement with PVR Partners, L.P. ("PVR") pursuant to which the Partnership intends to merge with PVR ("PVR Acquisition"). This merger will be a unit-for-unit transaction plus a one-time $37 million cash payment to PVR unitholders which represents total consideration of $5.6 billion, including the assumption of net debt of $1.8 billion. The holders of PVR common units, PVR Class B Units and PVR Special Units ("PVR Unit(s)") will receive 1.02 Partnership common units in exchange for each PVR Unit held on the applicable record date. In November 2013, the Partnership received approval of the PVR Acquisition under the Hart-Scott-Rodino Antitrust Improvements Act. The transaction is subject to the approval of PVR's unitholders and other customary closing conditions, and is expected to close in March 2014.

The PVR Acquisition is expected to enhance our geographic diversity with a strategic presence in the Marcellus and Utica shales in the Appalachian Basin and the Granite Wash in the Mid-Continent region.

Eagle Rock Acquisition. In December, 2013, the Partnership entered into an agreement to purchase Eagle Rock Energy Partners, L.P.'s ("Eagle Rock's") midstream business for approximately $1.3 billion (the "Eagle Rock Midstream Acquisition"). This acquisition is expected to complement the Partnership's core gathering and processing business, and when combined with the PVR Acquisition, is expected to further diversify the Partnership's basin exposure in the Texas Panhandle, East Texas and South Texas. The Eagle Rock Midstream Acquisition is expected to close in the second quarter of 2014, and is subject to the approval of Eagle Rock unitholders, Hart-Scott-Rodino Antitrust Improvements Act approval and other customary closing conditions.

Hoover Energy Acquisition. On February 3, 2014, the Partnership completed its previously announced acquisition of the subsidiaries of Hoover Energy Partners, LP that are engaged in crude oil gathering, transportation and terminaling, condensate handling, natural gas gathering, treating and processing, and water gathering and disposal services in the southern Delaware Basin in West Texas. The consideration paid by the Partnership was valued at $281.6 million (subject to customary post-closing adjustments) and consisted of (i) 4,040,471 Regency common units issued to Hoover and (ii) $183.6 million in cash. A portion of the consideration is being held in escrow as security for certain indemnification claims. The Partnership financed the cash portion of the purchase price through borrowings under its revolving credit facility. The Partnership will account for the acquisition of Hoover using the acquisition method of accounting, which requires, among other things, that assets acquired and liabilities assumed be recognized on the balance sheet at their fair values as of the acquisition date. Management's evaluation of the assigned fair values is ongoing as the transaction was recently completed and therefore the Partnership was not able to complete the preliminary allocation of the purchase price to the acquired assets and liabilities prior to the issuance of these financial statements.

2011

Lone Star. On May 2, 2011, the Partnership contributed $593 million in cash to Lone Star NGL LLC ("Lone Star"), in exchange for its 30% interest. Lone Star, a newly formed joint venture that is owned 70% by ETP and 30% by the Partnership, completed its acquisition of all of the membership interest in LDH, a wholly-owned subsidiary of Louis Dreyfus Highbridge Energy LLC for $1.98 billion in cash. To fund a portion of this capital contribution, the Partnership issued 8,500,001 Regency common units representing limited partnership interests with net proceeds of $204 million. The remaining portion of the Partnership's capital contribution was funded by additional borrowings under its revolving credit facility.

Ranch JV. On December 2, 2011, Ranch Westex JV LLC ("Ranch JV") was formed by the Partnership, Anadarko Pecos Midstream LLC and Chesapeake West Texas Processing, L.L.C., each owning a 33.33% interest in the joint venture. Ranch JV processes natural gas delivered from the NGLs-rich Bone Spring and Avalon shale formations in West Texas.

5. Investments in Unconsolidated Affiliates

As of December 31, 2013, the Partnership has a 49.99% general partner interest in RIGS Haynesville Partnership Co. (“HPC”), a 50% membership interest in Midcontinent Express Pipeline LLC (“MEP”), a 30% membership interest in Lone Star, a 33.33% membership interest in Ranch JV, and a 50% membership interest in Grey Ranch. The Partnership acquired a 33.33% membership interest in Ranch JV in December 2011, a 30% interest in Lone Star in May 2011, a 49.9% interest in MEP in May 2010 and a 0.1% interest in MEP in September 2011. The carrying value of the Partnership’s investment in each of the unconsolidated affiliates as of December 31, 2013 and 2012 is as follows:

	December 31, 2013	December 31, 2012
HPC	$ 442	$ 650
MEP	548	581
Lone Star	1,070	948
Ranch JV	36	35
Grey Ranch	1	—
	$ 2,097	$ 2,214

The following tables summarize the changes in the Partnership’s investment activities in each of the unconsolidated affiliates for the years ended December 31, 2013, 2012 and 2011:

	Year Ended December 31, 2013				
	HPC [(2)]	MEP	Lone Star	Ranch JV	Grey Ranch
Contributions	$ —	$ —	$ 137	$ 2	$ —
Distributions	238	72	79	2	—
Share of net income	36	39	64	1	1
Amortization of excess fair value of investment [(1)]	(6)	—	—	—	—

	Year Ended December 31, 2012				
	HPC	MEP	Lone Star	Ranch JV	Grey Ranch
Contributions	$ —	$ —	$ 343	$ 36	$ —
Distributions	61	75	68	—	—
Share of net income	35	42	44	(1)	(9)
Amortization of excess fair value of investment [(1)]	(6)	—	—	—	—

	Year Ended December 31, 2011				
	HPC	MEP[(3)]	Lone Star[(4)]	Ranch JV	Grey Ranch
Contributions	$ —	$ —	$ 645	$ —	N/A
Purchase of additional interest	—	1	—	—	N/A
Distributions	65	83	22	—	N/A
Return of investment	—	—	23	—	N/A
Share of net income	55	43	28	—	N/A
Amortization of excess fair value of investment [(1)]	(6)	—	—	—	N/A

(1) The Partnership’s investment in HPC was adjusted to its fair value on May 26, 2010 and the excess fair value over net book value was comprised of two components: (1) $155 million was attributed to HPC’s long-lived assets and is being amortized as a reduction of income from unconsolidated affiliates over the useful lives of the respective assets, which vary from 15 to 30 years, and (2) $32 million could not be attributed to a specific asset and therefore will not be amortized in future periods.

(2) HPC entered into a $500 million 5-year revolving credit facility in September 2013, pursuant to which the Partnership pledged its 49.99% equity interest in HPC. Upon closing such credit facility, HPC borrowed $370 million to fund a non-recurring return of investment to its partners of which the Partnership received $185 million. The amount outstanding under this facility was $445 million as of December 31, 2013. The Partnership’s contingent obligation with respect to the outstanding borrowings under this facility was $222 million at December 31, 2013.

(3) In September 2011, the Partnership purchased an additional 0.1% interest in MEP from ETP for $1 million in cash, bringing the total membership interest to 50%.

(4) For the period from initial contribution, May 2, 2011, to December 31, 2011.

N/A The Partnership acquired a 50% interest in Grey Ranch in March 2012, as part of the SUGS Acquisition in April 2013.

6. Derivative Instruments

Policies. The Partnership established comprehensive risk management policies and procedures to monitor and manage the market risks associated with commodity prices, counterparty credit, and interest rates. The General Partner is responsible for delegation of transaction authority levels, and the Audit and Risk Committee of the General Partner is responsible for the overall management of these risks, including monitoring exposure limits. The Audit and Risk Committee receives regular briefings on exposures and overall risk management in the context of market activities.

Commodity Price Risk. The Partnership is a net seller of NGLs, condensate and natural gas as a result of its gathering and processing operations. The prices of these commodities are impacted by changes in the supply and demand as well as other market forces. Both the Partnership’s profitability and cash flow are affected by the inherent volatility of these commodities which could adversely affect its ability to make distributions to its unitholders. The Partnership manages this commodity price exposure through an integrated strategy that includes management of its contract portfolio, matching sales prices of commodities with purchases, optimization of its portfolio by monitoring basis and other price differentials in operating areas, and the use of derivative contracts. In some cases, the Partnership may not be able to match pricing terms or to cover its risk to price exposure with financial hedges, and it may be exposed to commodity price risk. Speculative positions with derivative contracts are prohibited under the Partnership’s policies.

The Partnership has swap contracts settled against NGLs (natural gas liquids, including propane, normal butane, iso butane and natural gasoline), condensate and natural gas market prices. The Partnership also had put options settled against ethane, which expired in December 2012.

On January 1, 2012, the Partnership de-designated its swap contracts and began accounting for these contracts using the mark-to-market method of accounting. As of December 31, 2013, the Partnership had an immaterial amount in net hedging gains in AOCI, all of which will be amortized to earnings over the next three months.

As of December 31, 2012, SUGS had outstanding receive-fixed natural gas price swaps with a total notional amount of 4,562,500 MMBtu for 2012. These natural gas price swaps were accounted for as cash flow hedges, with effective portion of changes in their fair value recorded to AOCI and reclassified into revenues in the same period which the forecasted natural gas sales impact earnings. As of April 30, 2013, in connection with the SUGS Acquisition, these outstanding hedges were terminated.

Interest Rate Risk. The Partnership is exposed to variable interest rate risk as a result of borrowings under its revolving credit facility. The Partnership's $250 million interest rate swaps expired in April 2012. As of December 31, 2013, the Partnership had $510 million of outstanding borrowings exposed to variable interest rate risk.

Credit Risk. The Partnership’s resale of NGLs, condensate, and natural gas exposes it to credit risk, as the margin on any sale is generally a very small percentage of the total sales price. Therefore, a credit loss can be very large relative to overall profitability on these transactions. The Partnership monitors credit exposure and attempts to ensure that it issues credit only to creditworthy counterparties and that in appropriate circumstances any such extension of credit is backed by adequate collateral, such as a letter of credit or parental guarantee from a parent company with potentially better credit.

The Partnership is exposed to credit risk from its derivative counterparties. The Partnership does not require collateral from these counterparties. The Partnership deals primarily with financial institutions when entering into financial derivatives, and utilizes master netting agreements that allow for netting of swap contract receivables and payables in the event of default by either party. If the Partnership’s counterparties failed to perform under existing swap contracts, the Partnership’s maximum loss as of December 31, 2013 was $4 million, which would be reduced by less than $1 million due to the netting feature. The Partnership has elected to present assets and liabilities under master netting agreements gross on the consolidated balance sheets.

Embedded Derivatives. The Regency Series A Preferred Units contain embedded derivatives which are required to be bifurcated and accounted for separately, such as the holders’ conversion option and the Partnership’s call option. These embedded derivatives are accounted for using mark-to-market accounting. The Partnership does not expect the embedded derivatives to affect its cash flows.

The Partnership's derivative assets and liabilities, including credit risk adjustments, as of December 31, 2013 and 2012 are detailed below:

	Assets		Liabilities	
	December 31, 2013	December 31, 2012	December 31, 2013	December 31, 2012
Derivatives designated as cash flow hedges				
Current amounts				
Commodity contracts	$ —	$ —	$ —	$ 5
Total cash flow hedging instruments	—	—	—	5
Derivatives not designated as cash flow hedges				
Current amounts				
Commodity contracts	$ 3	$ 4	$ 9	$ 1
Long-term amounts				
Commodity contracts	1	1	—	—
Embedded derivatives in Series A Preferred Units	—	—	19	25
Total derivatives	$ 4	$ 5	$ 28	$ 31

The Partnership's statements of operations for the years ended December 31, 2013, 2012 and 2011 were impacted by derivative instruments activities as detailed below:

		Years Ended December 31,		
		2013	2012	2011
Derivatives in cash flow hedging relationships:		Change in Value Recognized in AOCI on Derivatives (Effective Portion)		
Commodity derivatives		$ —	$ (4)	$ (13)
Derivatives in cash flow hedging relationships:	**Location of Gain/(Loss) Recognized in Income**	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)		
Commodity derivatives	Revenue	$ —	$ 6	$ (19)

		Years Ended December 31,		
		2013	2012	2011
Derivatives not designated in a hedging relationship:	**Location of Gain/(Loss) Recognized in Income**	Amount of Gain/(Loss) from De-designation Amortized from AOCI into Income		
Commodity derivatives	Revenue	$ —	$ (5)	$ —
Derivatives not designated in a hedging relationship:	**Location of Gain/(Loss) Recognized in Income**	Amount of Gain/(Loss) Recognized in Income on Derivatives		
Commodity derivatives	Revenue	$ (9)	$ 16	$ —
Embedded derivatives	Other income & deductions	6	14	18
		$ (3)	$ 30	$ 18

7. Long-term Debt

Obligations in the form of senior notes and borrowings under the credit facilities are as follows:

	December 31, 2013	December 31, 2012
Senior notes	$ 2,800	$ 1,965
Revolving loans	510	192
Total	3,310	2,157
Less: current portion	—	—
Long-term debt	$ 3,310	$ 2,157
Availability under revolving credit facility:		
Total credit facility limit	$ 1,200	$ 1,150
Revolving loans	(510)	(192)
Letters of credit	(14)	(12)
Total available	$ 676	$ 946

Long-term debt maturities as of December 31, 2013 for each of the next five years are as follows:

Year Ended December 31,	Amount
2014	$ —
2015	—
2016	—
2017	—
2018	600
Thereafter	2,710
Total	$ 3,310

Revolving Credit Facility

In the year ended December 31, 2013, 2012 and 2011 the Partnership borrowed $1.46 billion, $1.56 billion and $940 million, respectively, under its revolving credit facility; these borrowings were to fund capital expenditures and acquisitions. During the same periods, the Partnership repaid $1.1 billion, $1.70 billion and $893 million, respectively, with proceeds from equity offerings and issuances of senior notes.

In May 2013, Regency Gas Services, LP, a wholly-owned subsidiary of Regency Energy Partners LP, entered into the Sixth Amended and Restated Credit Agreement to increase the commitment to $1.2 billion with a $300 million uncommitted incremental facility and extended the maturity date to May 21, 2018. The material differences between the Fifth and Sixth Amended and Restated Credit Agreement include:

- A 75 bps decrease in pricing, with an additional 50 bps decrease upon the achievement of an investment grade rating;
- No limitation on the maximum amount that the loan parties may invest in joint ventures existing on the date of the credit agreement so long as the Partnership is in pro forma compliance with the financial covenants;
- The addition of a “Restricted Subsidiary” structure such that certain designated subsidiaries are not subject to the credit facility covenants and do not guarantee the obligations thereunder or pledge their assets in support thereof;
- The addition of provisions such that upon the achievement of an investment grade rating by the Partnership, the collateral package will be released; the facility will become unsecured; and the covenant package will be significantly reduced;
- An eight-quarter increase in the permitted Total Leverage Ratio; and
- After March 2015, an increase in the permitted total leverage ratio for the two fiscal quarters following any $50 million or greater acquisition.

The Partnership capitalized $6 million of net loan fees which is being amortized over the remaining term.

The revolving credit facility and the guarantees are senior to the Partnership’s and the guarantors’ unsecured obligations, to the extent of the value of the assets securing such obligations.

As of December 31, 2013, the Partnership was in compliance in all material respects with all of the financial covenants contained within the new credit agreement.

The outstanding balance under the revolving credit facility bears interest at LIBOR plus a margin or alternate base rate (equivalent to the U.S. prime lending rate) plus a margin, or a combination of both. The alternate base rate used to calculate interest on base rate loans will be calculated based on the greatest to occur of a base rate, a federal funds effective rate plus 0.50% and an adjusted one-month LIBOR rate plus 1.00%. The applicable margin shall range from 0.625% to 1.50% for base rate loans, 1.625% to 2.50% for Eurodollar loans. The weighted average interest rate on the total amounts outstanding under the Partnership's revolving credit facility was 2.17% and 2.93% as of December 31, 2013 and 2012, respectively.

RGS must pay (i) a commitment fee ranging from 0.30% to 0.45% per annum of the unused portion of the revolving loan commitments, (ii) a participation fee for each revolving lender participating in letters of credit ranging from 1.625% to 2.50% per annum of the average daily amount of such lender's letter of credit exposure and (iii) a fronting fee to the issuing bank of letters of credit equal to 0.20% per annum of the average daily amount of the letter of credit exposure. These fees are included in interest expense, net in the consolidated statement of operations.

The revolving credit facility contains financial covenants requiring RGS and its subsidiaries to maintain a debt to consolidated EBITDA (as defined in the credit agreement) ratio less than 5.00 for the first eight quarters (after March 2015, an increase is allowed in the permitted total leverage ratio for the first two fiscal quarters following any $50 million or greater acquisition), consolidated EBITDA to consolidated interest expense ratio greater than 2.50 and a secured debt to consolidated EBITDA ratio less than 3.25. At December 31, 2013 and 2012, RGS and its subsidiaries were in compliance with these covenants.

The revolving credit facility restricts the ability of RGS to pay dividends and distributions other than reimbursements of the Partnership for expenses and payment of dividends to the Partnership to the amount of available cash (as defined) so long as no default or event of default has occurred or is continuing. The revolving credit facility also contains various covenants that limit (subject to certain exceptions), among other things, the ability of RGS to:

- incur indebtedness;
- grant liens;
- enter into sale and leaseback transactions;
- make certain investments, loans and advances;
- dissolve or enter into a merger or consolidation;
- enter into asset sales or make acquisitions;
- enter into transactions with affiliates;
- prepay other indebtedness or amend organizational documents or transactions documents (as defined in the revolving credit facility);
- issue capital stock or create subsidiaries; or
- engage in any business other than those businesses in which it was engaged at the time of the effectiveness of the revolving credit facility or reasonable extension thereof.

In February 2014, RGS entered into the first Amendment to the Sixth Amended and restated Credit Agreement to, among other things, expressly permit the pending PVR and Eagle Rock acquisitions, and to increase the commitment to $1.5 billion and increase the uncommitted incremental facility to $500 million. The amendment will specifically allows the Partnership to assume the series of PVR senior notes that mature prior to the credit agreement.

Senior Notes

In May 2009, the Partnership and Regency Energy Finance Corp., a wholly-owned subsidiary of the Partnership, issued $250 million of senior notes that mature on June 1, 2016 (the "2016 Notes"). The 2016 Notes bear interest at 9.375% with interest payable semi-annually in arrears on June 1 and December 1. In May 2012, the Partnership redeemed 35%, or $87 million, of the 2016 Notes, bringing the total outstanding principal amount to $163 million. A redemption premium of $8 million was charged to loss on debt refinancing, net in the consolidated statement of operations and $4 million of accrued interest was paid. The Partnership also wrote off the unamortized loan fee of $1 million and unamortized bond premium of $2 million to loss on debt refinancing, net in the consolidated statement of operations. In June 2013, the Partnership redeemed all amounts outstanding 2016 Notes for $178 million cash, inclusive of accrued and unpaid interest of $7 million and other fees and expenses.

The Partnership and Finance Corp. have outstanding the following series of senior notes (collectively "Senior Notes"):

- $600 million in aggregate principal amount of our 6 ⅞% senior notes due December 1, 2018 (the "2018 Notes") with interest payable semi-annually in arrears on June 1 and December 1;
- $400 million in aggregate principal amount of our 5 ¾% senior notes due September 1, 2020 (the "2020 Notes") with interest payable semi-annually in arrears on March 1 and September 1;
- $500 million in aggregate principal amount of our 6 ½% senior notes due July 15, 2021 (the "2021 Notes") with interest payable semi-annually in arrears on January 15 and July 15;
- $900 million in aggregate principal of our 5 ⅞% senior notes due March 1, 2022 (the "2022 Notes") issued in February 2014, with interest payable semi-annually in arrears on March 1 and September 1;
- $700 million in aggregate principal amount of our 5 ½% senior notes due April 15, 2023 (the "2023 5 ½% Notes") with interest payable semi-annually in arrears on April 15 and October 15; and
- $600 million in aggregate principal amount of our 4 ½% senior notes due November 1, 2023 (the "2023 4 ½% Notes") with interest payable semi-annually in arrears on May 1 and November 1.

The Senior Notes are guaranteed by our existing consolidated subsidiaries except Finance Corp and ELG.

The Senior Notes are redeemable at any time prior to the dates specified below at a price equal to 100% of the principal amount of the applicable series, plus a make-whole premium and accrued and unpaid interest, if any, to the redemption date.

- 2018 Notes - Beginning December 1, 2014 100% may be redeemed at fixed redemption price of 103.438% (December 1, 2015 - 101.719% and December 1, 2016 and thereafter - 100%) plus accrued and unpaid interest, if any, to the redemption date
- 2020 Notes - Redeemable, in whole or in part, prior to June 1, 2020 at 100% of the principal amount plus a make-whole premium and accrued and unpaid interest, if any, to the redemption date; redeemable, in whole or in part, on or after June 1, 2020 at 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date
- 2021 Notes - Any time prior to July 15, 2014, up to 35% may be redeemed at a price of 106.5% plus accrued and unpaid interest, if any; beginning July 15, 2016, 100% may be redeemed at fixed redemption price of 103.25% (July 15, 2017 - 102.167%, July 15, 2018 - 101.083% and July 15, 2019 and thereafter - 100%) plus accrued and unpaid interest, if any, to the redemption date
- 2022 Notes - Redeemable, in whole or in part, prior to December 1, 2021 at 100% at the principal amount plus a make-whole premium and accrued and unpaid interest, if any, to the redemption date; redeemable, in whole or in part, on or after December 1, 2021 at 100% at the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date
- 2023 5 ½% Notes - Any time prior to October 15, 2015, up to 35% may be redeemed at a price of 105.5% plus accrued and unpaid interest, if any; beginning October 15, 2017, 100% may be redeemed at fixed redemption price of 102.75% (October 15, 2018 - 101.833%, October 15, 2019 - 100.917% and October 15, 2020 and thereafter - 100%) plus accrued and unpaid interest, if any, to the redemption date
- 2023 4 ½% Notes - Redeemable, in whole or in part, prior to August 1, 2023 at 100% of the principal amount plus a make-whole premium and accrued and unpaid interest, if any, to the redemption date; redeemable, in whole or in part, on or after August 1, 2023 at 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date

Upon a change of control followed by a ratings downgrade within 90 days of a change of control, each note holder of the Senior Notes will be entitled to require us to purchase all or a portion of its notes at a purchase price of 101% plus accrued and unpaid interest, if any. The Partnership's ability to purchase the Senior Notes upon a change of control will be limited by the terms of our debt agreements, including the Partnership's revolving credit facility.

The existing senior notes contain various covenants that limit, among other things, our ability, and the ability of certain of our subsidiaries, to:

- incur additional indebtedness;
- pay distributions on, or repurchase or redeem our equity interests;
- make certain investments;
- incur liens;
- enter into certain types of transactions with affiliates; and
- sell assets or consolidate or merge with or into other companies.

If the Senior Notes achieve investment grade ratings by both Moody’s and Standard & Poor’s and no default or event of default has occurred and is continuing, we will no longer be subject to many of the foregoing covenants. At December 31, 2013, we were in compliance with these covenants.

8. Intangible Assets

Activity related to intangible assets, net consisted of the following:

	Customer Relations	Trade Names	Total
Balance at January 1, 2012	$ 681	$ 60	$ 741
Amortization	(26)	(3)	(29)
Balance at December 31, 2012	655	57	712
Amortization	(26)	(4)	(30)
Balance at December 31, 2013	$ 629	$ 53	$ 682

The average remaining amortization periods for customer relations and trade names are 24 and 16 years, respectively. The expected amortization of the intangible assets for each of the five succeeding years is $30 million.

9. Fair Value Measures

The fair value measurement provisions establish a three-tiered fair value hierarchy that prioritizes inputs to valuation techniques used in fair value calculations. The three levels of inputs are defined as follows:

- Level 1—unadjusted quoted prices for identical assets or liabilities in active accessible markets;
- Level 2—inputs that are observable in the marketplace other than those classified as Level 1; and
- Level 3—inputs that are unobservable in the marketplace and significant to the valuation.

Entities are encouraged to maximize the use of observable inputs and minimize the use of unobservable inputs. If a financial instrument uses inputs that fall in different levels of the hierarchy, the instrument will be categorized based upon the lowest level of input that is significant to the fair value calculation.

The Partnership's financial assets and liabilities measured at fair value on a recurring basis are derivatives related to commodity swaps and embedded derivatives in the Regency Series A Preferred Units. Derivatives related to commodity swaps are valued using observable inputs for similar instruments and incorporate Level 1 and Level 2 inputs. Embedded derivatives related to the Regency Series A Preferred Units are valued using a binomial lattice model. The market inputs utilized in the model include credit spread, probabilities of the occurrence of certain events, common unit price, dividend yield, and expected volatility, and are classified as Level 3.

The following table presents the Partnership’s derivative assets and liabilities measured at fair value on a recurring basis:

	Fair Value Measurement at December 31, 2013			Fair Value Measurement at December 31, 2012		
	Fair Value Total	Level 2	Level 3	Fair Value Total	Level 2	Level 3
Assets						
Commodity Derivatives:						
Natural Gas	$ 2	$ 2	$ —	$ 2	$ 2	$ —
Natural Gas Liquids	2	2	—	1	1	—
Condensate	—	—	—	2	2	—
Total Assets	$ 4	$ 4	$ —	$ 5	$ 5	$ —
Liabilities						
Commodity Derivatives:						
Natural Gas	$ 4	$ 4	$ —	$ 5	$ 5	$ —
Natural Gas Liquids	4	4	—	1	1	—
Condensate	1	1	—	—	—	—
Embedded Derivatives in Regency Series A Preferred Units	19	—	19	25	—	25
Total Liabilities	$ 28	$ 9	$ 19	$ 31	$ 6	$ 25

The following table presents the material unobservable inputs used to estimate the fair value of the embedded derivatives in the Regency Series A Preferred Units:

Unobservable Input	December 31, 2013
Credit Spread	4.16%
Volatility	23.71%

Changes in the Partnership's cost of equity and U.S. Treasury yields would cause a change in the credit spread used to value the embedded derivatives. Changes in the Partnership's historical unit price volatility would cause a change in the volatility used to value the embedded derivatives.

The following table presents the changes in Level 3 derivatives measured on a recurring basis for the years ended December 31, 2013 and 2012. There were no transfers between Level 2 and Level 3 derivatives for the years ended December 31, 2013 and 2012.

	Embedded Derivatives in Series A Preferred Units
Balance at January 1, 2012	$ 39
Change in fair value	(14)
Balance at December 31, 2012	25
Change in fair value, net of gain at conversion of $26 million	(6)
Balance at December 31, 2013	$ 19

The carrying amount of cash and cash equivalents, accounts receivable and accounts payable approximates fair value due to their short-term maturities. Long-term debt, other than the Senior Notes, is comprised of borrowings under which interest accrues under a floating interest rate structure. Accordingly, the carrying value approximates fair value.

The aggregate fair value and carrying amount of the Senior Notes at December 31, 2013 was $2.83 billion and $2.80 billion, respectively. As of December 31, 2012, the aggregate fair value and carrying amount of the Senior Notes was $2.13 billion and $1.97 billion, respectively. The fair value of the Senior Notes is a Level 1 valuation based on third party market value quotations.

10. Leases

The following table is a schedule of future minimum lease payments for office space and certain equipment leased by the Partnership, that had initial or remaining non-cancelable lease terms in excess of one year as of December 31, 2013:

For the year ending December 31,	Operating Lease
2014	$ 3
2015	3
2016	2
2017	2
2018	2
Thereafter	34
Total minimum lease payments	$ 46

Total rent expense for operating leases, including those leases with terms of less than one year, was $11 million, $11 million and $3 million for the years ended December 31, 2013, 2012 and 2011, respectively.

11. Commitments and Contingencies

Legal. The Partnership is involved in various claims, lawsuits and audits by taxing authorities incidental to its business. These claims and lawsuits in the aggregate are not expected to have a material adverse effect on the Partnership's business, financial condition, results of operations or cash flows.

PVR Shareholder Litigation. Five putative class action lawsuits challenging the PVR Acquisition are currently pending. All of the cases name PVR, PVR GP and the current directors of PVR GP, as well as the Partnership and the General Partner (collectively, the "Regency Defendants"), as defendants. Each of the lawsuits has been brought by a purported unitholder of PVR, both individually and on behalf of a putative class consisting of public unitholders of PVR. The lawsuits generally allege, among other things, that the directors of PVR GP breached their fiduciary duties to unitholders of PVR, that PVR GP, PVR and the Regency Defendants aided and abetted the directors of PVR GP in the alleged breach of these fiduciary duties, and, as to the actions in federal court, that some or all of PVR, PVR GP, and the directors of PVR GP violated Section 14(a) of the Exchange Act and Rule 14a-9 promulgated thereunder and Section 20(a) of the Exchange Act. The lawsuits purport to seek, in general, (i) injunctive relief, (ii) disclosure of certain additional information concerning the transaction, (iii) in the event the merger is consummated, rescission or an award of rescissory damages, (iv) an award of plaintiffs' costs and (v) the accounting for damages allegedly causes by the defendants to these actions, and, (iv) such further relief as the court deems just and proper. The styles of the pending cases are as follows: David Naiditch v. PVR Partners, L.P., et al. (Case No. 9015-VCL) in the Court of Chancery of the State of Delaware); Charles Monatt v. PVR Partners, LP, et al. (Case No. 2013-10606) and Saul Srour v. PVR Partners, L.P., et al. (Case No. 2013-011015), each pending in the Court of Common Pleas for Delaware County, Pennsylvania; Stephen Bushansky v. PVR Partners, L.P., et al. (C.A. No. 2:13-cv-06829-HB); and Mark Hinnau v. PVR Partners, L.P., et al. (C.A. No. 2:13-cv-07496-HB), pending in the United States District Court for the Eastern District of Pennsylvania.

On January 28, 2014, the defendants entered into a Memorandum of Understanding ("MOU") with Monatt, Srour, Bushansky, Naiditch and Hinnau pursuant to which defendants and the referenced plaintiffs agreed in principle to a settlement of their lawsuits ("Settled Lawsuits"), which will be memorialized in a separate settlement agreement, subject to customary conditions, including consummation of the PVR Acquisition, completion of certain confirmatory discovery, class certification and final approval by the Court of Common Pleas for Delaware County, Pennsylvania. If the Court approves the settlement, the Settled Lawsuits will be dismissed with prejudice and all defendants will be released from any and all claims relating to the Settled Lawsuits.

The settlement will not affect any provisions of the merger agreement or the form or amount of consideration to be received by PVR unitholders in the PVR Acquisition. The defendants have denied and continue to deny any wrongdoing or liability with respect to the plaintiffs' claims in the aforementioned litigation and have entered into the settlement to eliminate the uncertainty, burden, risk, expense, and distraction of further litigation.

Environmental. The Partnership is responsible for environmental remediation at certain sites on its gathering and processing systems, resulting primarily from releases of hydrocarbons. The Partnership's remediation program typically involves the management of contaminated soils and may involve remediation of groundwater. Activities vary with site conditions and locations, the extent and nature of the contamination, remedial requirements and complexity. The ultimate liability and total costs associated with these sites will depend upon many factors.

The table below reflects the environmental liabilities recorded in the consolidated balance sheet at December 31, 2013 and 2012 where management believes a loss is probable and reasonably estimable. The Partnership does not have any material environmental remediation matters assessed as reasonably possible that would require disclosure in the financial statements.

	December 31, 2013	December 31, 2012
Current	$ 2	$ 5
Noncurrent	6	7
Total environmental liabilities	$ 8	$ 12

The Partnership made expenditures related to environmental remediation of $5 million for the year ended December 31, 2013.

Air Quality Control. The Partnership is currently negotiating settlements to certain enforcement actions by the NMED and the TCEQ. The TCEQ recently initiated a state-wide emissions inventory for the sulfur dioxide emissions from sites with reported emissions of 10 tons per year or more. If this data demonstrates that any source or group of sources may cause or contribute to a violation of the National Ambient Air Quality Standards, they must be sufficiently controlled to ensure timely attainment of the standard. This may potentially affect three SUGS recovery units in Texas. It is unclear at this time how the NMED will address the sulfur dioxide standard.

Compliance Orders from the NMED. SUGS has been in discussions with the NMED concerning allegations of violations of New Mexico air regulations related to the Jal #3 and Jal #4 facilities. Hearings on the COs were delayed until March 2014 to allow the parties to pursue substantive settlement discussions. The Partnership has meritorious defenses to the NMED claims and can offer significant mitigating factors to the claimed violations. The Partnership has recorded a liability of less than $1 million related to the claims and will continue to assess its potential exposure to the allegations as the matters progress.

CDM Sales Tax Audit. CDM Resource Management LLC (“CDM”), a subsidiary of the Partnership, has historically claimed the manufacturing exemption from sales tax in Texas, as is common in the industry. The exemption is based on the fact that CDM's natural gas compression equipment is used in the process of treating natural gas for ultimate use and sale. In a recent audit by the Texas Comptroller's office, the Comptroller has challenged the applicability of the manufacturing exemption to CDM. The period being audited is from August 2006 to August 2007, and liability for that period is potentially covered by an indemnity obligation from CDM's prior owners. CDM may also have liability for periods since 2008, and prospectively, if the Comptroller's challenge is ultimately successful. An audit of the 2008 period has commenced. In April 2013, an independent audit review agreed with the Comptroller's position. While CDM continues to disagree with this position and intends to seek redetermination and other relief, the Partnership is unable to predict the final outcome of this matter.

In addition to the matters discussed above, the Partnership is involved in legal, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies regarding matters arising in the ordinary course of business, none of which are believed to be potentially material to the Partnership at this time.

12. Regency Series A Preferred Units

On September 2, 2009, the Partnership issued 4,371,586 Regency Series A Preferred Units at a price of $18.30 per unit, less issuance costs and a 4% discount of $3 million for net proceeds of $77 million, exclusive of the General Partner’s contribution of $2 million. The Regency Series A Preferred Units are convertible to Regency common units under terms described below, and if outstanding, are mandatorily redeemable on September 2, 2029 for $35 million plus all accrued but unpaid distributions thereon (the “Series A Liquidation Value”) and accrued interest. The Regency Series A Preferred Units receive fixed quarterly cash distributions of $0.445 per unit which began with the quarter ending March 31, 2010.

Holders may elect to convert Regency Series A Preferred Units to common units at any time. In July 2013, certain holders of Regency Series A Preferred Units exercised their right to convert 2,459,017 Regency Series A Preferred Units into Regency common units. Concurrent with this transaction, the Partnership recognized a $26 million gain in other income and deductions, net, related to the embedded derivative and reclassified $41 million from the Regency Series A Preferred Units into Regency common units. As of December 31, 2013, the remaining Regency Series A Preferred Units were convertible into 2,050,854 Regency common units, and if outstanding, are mandatorily redeemable on September 2, 2029 for $35 million plus all accrued but unpaid distributions and interest thereon. The Regency Series A Preferred Units receive fixed quarterly cash distributions of $0.445 per unit if outstanding on the record dates of the Partnership’s common unit distributions.

Distributions on the Regency Series A Preferred Units were accrued for the first two quarters (and not paid in cash) and will result in an increase in the number of Regency common units issuable upon conversion. If on any distribution payment date beginning March 31, 2010, the Partnership (1) fails to pay distributions on the Regency Series A Preferred Units, (2) reduces the distributions on the Regency common units to zero and (3) is prohibited by its material financing agreements from paying cash distributions, such distributions shall automatically accrue and accumulate until paid in cash. If the Partnership has failed to pay cash distributions in full for two quarters (whether or not consecutive) from and including the quarter ended on March 31, 2010, then if the Partnership fails to pay cash distributions on the Regency Series A Preferred Units, all future distributions on the Regency Series A Preferred Units that are accrued rather than being paid in cash by the Partnership will consist of the following: (1) $0.35375 per Regency Series A Preferred Unit per quarter, (2) $0.09125 per Regency Series A Preferred Unit per quarter (the “Common Unit Distribution Amount”), payable solely in common units, and (3) $0.09125 per Regency Series A Preferred Unit per quarter (the “PIK Distribution Additional Amount”), payable solely in common units. The total number of common units payable in connection with the Common Unit Distribution Amount or the PIK Distribution Additional Amount cannot exceed $2 million in any period of 20 consecutive fiscal quarters.

Upon the Partnership’s breach of certain covenants (a “Covenant Default”), the holders of the Regency Series A Preferred Units will be entitled to an increase of $0.1825 per quarterly distribution, payable solely in common units (the “Covenant Default Additional Amount”). All accumulated and unpaid distributions will accrue interest (i) at a rate of 2.432% per quarter, or (ii) if the Partnership has failed to pay all PIK Distribution Additional Amounts or Covenant Default Additional Amounts or any Covenant Default has occurred and is continuing, at a rate of 3.429% per quarter while such failure to pay or such Covenant Default continues.

The Regency Series A Preferred Units are convertible, at the holder’s option, into Regency common units, provided that the holder must request conversion of at least 375,000 Regency Series A Preferred Units. The conversion price will initially be $18.30, subject to adjustment for customary events (such as unit splits). The number of Regency common units issuable is equal to the issue price of the Regency Series A Preferred Units (i.e. $18.30) being converted plus all accrued but unpaid distributions and accrued but unpaid interest thereon (the “Redeemable Face Amount”), divided by the applicable conversion price.

Commencing on September 2, 2014, if at any time the volume-weighted average trading price of the common units over the trailing 20-trading day period (the “VWAP Price”) is less than the then-applicable conversion price, the conversion ratio will be increased to: the quotient of (1) the Redeemable Face Amount on the date that the holder’s conversion notice is delivered, divided by (2) the product of (x) the VWAP Price set forth in the applicable conversion notice and (y) 91%, but will not be less than $10.

Also commencing on September 2, 2014, the Partnership will have the right at any time to convert all or part of the Regency Series A Preferred Units into Regency common units, if (1) the daily volume-weighted average trading price of the common units is greater than 150% of the then-applicable conversion price for 20 out of the trailing 30 trading days, and (2) certain minimum public float and trading volume requirements are satisfied.

In the event of a change of control, the Partnership will be required to make an offer to the holders of the Regency Series A Preferred Units to purchase their Regency Series A Preferred Units for an amount equal to 101% of their Series A Liquidation Value. In addition, in the event of certain business combinations or other transactions involving the Partnership in which the holders of common units receive cash consideration exclusively in exchange for their common units (a “Cash Event”), the Partnership must use commercially reasonable efforts to ensure that the holders of the Regency Series A Preferred Units will be entitled to receive a security issued by the surviving entity in the Cash Event with comparable powers, preferences and rights to the Regency Series A Preferred Units. If the Partnership is unable to ensure that the holders of the Regency Series A Preferred Units will be entitled to receive such a security, then the Partnership will be required to make an offer to the holders of the Regency Series A Preferred Units to purchase their Regency Series A Preferred Units for an amount equal to 120% of their Series A Liquidation Value. If the Partnership enters into any recapitalization, reorganization, consolidation, merger, spin-off that is not a Cash Event, the Partnership will make appropriate provisions to ensure that the holders of the Series A Preferred Units receive a security with comparable powers, preferences and rights to the Regency Series A Preferred Units upon consummation of such transaction. Subsequent to the ETE Acquisition, no unitholder exercised this option.

As of December 31, 2013, the Series A Preferred Units were convertible to 2,050,854 common units.

The following table provides a reconciliation of the beginning and ending balances of the Regency Series A Preferred Units for the year ended December 31, 2013 and 2012:

	Units	Amount
Balance at January 1, 2012	4,371,586	$ 71
Accretion to redemption value	N/A	2
Balance at December 31, 2012	4,371,586	73
Regency Series A Preferred Units converted into common units	(2,459,017)	(41)
Balance at December 31, 2013	1,912,569	$ 32 *

* This amount will be accreted to $35 million plus any accrued but unpaid distributions and interest by deducting amounts from

partners' capital over the remaining periods until the mandatory redemption date of September 2, 2029. Accretion during 2013 was immaterial.

13. Related Party Transactions

As of December 31, 2013 and 2012, details of the Partnership's related party receivables and related party payables were as follows:

	December 31, 2013	December 31, 2012
Related party receivables		
HPC	$ 1	$ 1
ETE and its subsidiaries	25	5
Ranch JV	2	2
Total related party receivables	$ 28	$ 8
Related party payables		
HPC	$ 1	$ 1
ETE and its subsidiaries	68	94
Total related party payables	$ 69	$ 95

Transactions with ETE and its subsidiaries. Under the service agreement with ETE Services Company, LLC ("Services Co."), the Partnership paid Services Co.'s direct expenses for services performed, plus an annual fee of $10 million, and received the benefit of any cost savings recognized for these services. The services agreement has a five year term ending May 26, 2015, subject to earlier termination rights in the event of a change in control, the failure to achieve certain cost savings for the Partnership or upon an event of default. On April 30, 2013, this agreement was amended to provide for a waiver of the $10 million annual fee effective as of May 1, 2013 through and including April 30, 2015 and to clarify the scope and expenses chargeable as direct expenses thereunder.

On April 30, 2013, the Partnership entered into the second amendment (the "Operation and Service Amendment") to the Operation and Service Agreement (the "Operation and Service Agreement"), by and among the Partnership, Energy Transfer Company ("ETC"), the General Partner and RGS. Under the Operation and Service Agreement, ETC performs certain operations, maintenance and related services reasonably required to operate and maintain certain facilities owned by the Partnership, and the Partnership reimburses ETC for actual costs and expenses incurred in connection with the provision of these services based on an annual budget agreed upon by both parties. The Operation and Service Agreement Amendment describes the services that ETC will provide in the future.

The Partnership incurred total service fees related to the agreements described above from ETE and its subsidiaries of $11 million for the year ended December 31, 2013, and $17 million for the years ended December 31, 2012 and 2011.

In conjunction with distributions made by the Partnership to the limited and general partner interests, ETE received cash distributions of $63 million, $62 million and $57 million for the years ended December 31, 2013, 2012 and 2011, respectively.

The General Partner has the right, but not the obligation, to contribute a proportionate amount of capital to the Partnership to maintain its general partner interest. No capital contributions were contributed during the years ended December 31, 2013 and 2012, respectively.

In September 2011, the Partnership purchased a 0.1% interest in MEP from ETP for $1 million in cash.

The Partnership's gathering and processing operations, in the ordinary course of business, sells natural gas and NGL to subsidiaries of ETE and records the revenue in gas sales and NGL sales. The Partnership's contract services operations provides contract compression services to ETP and records revenue in gathering, transportation and other fees on the statement of operations. The Partnership's contract services operations did not sell compression equipment to a subsidiary of ETP for the year ended December 31, 2013, and sold $1 million for the year ended December 31, 2012. As these transactions are between entities under common control, partners' capital was increased, which represented a deemed contribution of the excess sales price over the carrying amounts. The Partnership's contract services operations purchased compression equipment from a subsidiary of ETP for $95 million and $29 million during the years ended December 31, 2013 and 2012, respectively.

Prior to April 30, 2013, Southern Union provided certain administrative services for SUGS that were either based on SUGS's pro-rata share of combined net investment, margin and certain expenses or direct costs incurred by Southern Union on the behalf of SUGS. Southern Union also charged a management and royalty fee to SUGS for certain management support services provided by Southern Union on the behalf of SUGS and for the use of certain Southern Union trademarks, trade names and service marks by SUGS. The amounts were $21 million and $1 million for the period from March 26, 2012 to December 31, 2012. These administrative services were no longer being provided subsequent to the SUGS Acquisition.

Transactions with HPC. Under a Master Services Agreement with HPC, the Partnership operates and provides all employees and services for the operation and management of HPC. For the years ended December 31, 2013, 2012, and 2011, the related party general and administrative expenses reimbursed to the Partnership were $18 million, $20 million, and $17 million, respectively, which is recorded in gathering, transportation and other fees on the statements of operations.

The Partnership's contract services operations provides compression services to HPC and records revenue in gathering, transportation and other fees on the statement of operations. The Partnership also receives transportation services from HPC and records the cost as cost of sales.

Transactions with Lone Star. In 2013, the Partnership entered into a nineteen month agreement to sell NGL to Lone Star for approximately $5 million per month. For the year ended December 31, 2013, the Partnership had recorded $26 million in NGL sales under this contract.

Transactions with Enterprise Product Partners L.P. and its subsidiaries. In January 2012, Enterprise Products Partners L.P. ("EPD") sold a significant portion of its ownership in ETE's common units, and subsequent to that transaction, owns less than 5% of ETE's outstanding common units. As such, EPD is no longer considered a related party. During 2011, EPD owned a portion of ETE's outstanding common units and therefore was considered a related party along with any of its subsidiaries. The Partnership, in the ordinary course of business, sells natural gas and NGLs to subsidiaries of EPD and records the revenue in gas sales and NGL sales. The Partnership also incurs NGL processing fees and transportation fees with subsidiaries of EPD and records these fees as cost of sales.

14. Concentration Risk

The following table provides information about the extent of reliance on major customers and gas suppliers. Total revenues and cost of sales from transactions with an external customer or supplier amounting to 10% or more of revenue or cost of gas and liquids are disclosed below, together with the identity of Regency's reporting segment.

	Regency Reportable Segment	Years Ended December 31, 2013	2012	2011
Customer				
Customer A	Gathering and Processing	$ 381	$ 367	$ 366
Customer B	Gathering and Processing	362	451	—
Supplier				
Supplier A	Gathering and Processing	164	171	133
Supplier B	Gathering and Processing	185	—	—

Regency is a party to various commercial netting agreements that allow it and contractual counterparties to net receivable and payable obligations. These agreements are customary and the terms follow standard industry practice. In the opinion of management, these agreements reduce the overall counterparty risk exposure.

15. Regency's Equity-Based Compensation

In December 2011, Regency's unitholders approved the Regency Energy Partners LP 2011 Long-Term Incentive Plan (the "2011 Incentive Plan"), which provides for awards of options to purchase Regency's common units; awards of Regency's restricted units, Regency phantom units and Regency common units; awards of distribution equivalent rights; awards of common unit appreciation rights; and other unit-based awards to employees, directors and consultants of Regency and its affiliates and subsidiaries. The 2011 Incentive Plan will be administered by Regency's Compensation Committee of its board of directors, which may, in its sole discretion, delegate its powers and duties under the 2011 Incentive Plan to the Chief Executive Officer. Up to 3,000,000 of Regency's common units may be granted as awards under the 2011 Incentive Plan, with such amount subject to adjustment as provided for under the terms of the 2011 Incentive Plan.

The 2011 Incentive Plan may be amended or terminated at any time by Regency's board of directors or its Compensation Committee without the consent of any participant or unitholder, including an amendment to increase the number of Regency common units available for awards under the plan; however, any material amendment, such as a change in the types of Regency awards available under the plan, would require the Regency's unitholder approval. Regency's Compensation Committee is also authorized to make adjustments in the terms and conditions of, and the criteria included in awards under the 2011 Incentive Plan in specified circumstances. The 2011 Incentive Plan is effective until December 19, 2021 or, if earlier, the time at which all available units under the 2011 Incentive Plan have been issued to participants or the time of termination of the plan by Regency's board of directors.

Unit-based compensation expense of $7 million, $5 million, and $3 million is recorded in general and administrative expense in the statement of operations for the years ended December 31, 2013, 2012 and 2011, respectively.

Common Unit Options. The fair value of each option award is estimated on the date of grant using the Black-Scholes Option Pricing Model. Upon the exercise of the common unit options, the Partnership intends to settle these obligations with new issues of common units on a net basis. The common unit options activity for the years ended December 31, 2013, 2012, and 2011 is as follows:

2013

Common Unit Options	Units	Weighted Average Exercise Price
Outstanding at the beginning of period	156,550	$ 21.96
Exercised	(14,000)	21.14
Outstanding at end of period	142,550	22.04
Exercisable at the end of the period	142,550	

2012

Common Unit Options	Units	Weighted Average Exercise Price
Outstanding at the beginning of period	156,850	$ 21.99
Forfeited or expired	(300)	23.73
Outstanding at end of period	156,550	21.96
Exercisable at the end of the period	156,550	

2011

Common Unit Options	Units	Weighted Average Exercise Price
Outstanding at the beginning of period	201,950	$ 21.93
Exercised	(38,300)	20.84
Forfeited or expired	(6,800)	26.72
Outstanding at end of period	156,850	21.99
Exercisable at the end of the period	156,850	

The common unit options have an intrinsic value of less than $1 million related to non-vested units with a weighted average contractual term of 2.4 years. Intrinsic value is the closing market price of a unit less the option strike price, multiplied by the number of unit options outstanding as of the end of the period presented. Unit options with an exercise price greater than the end of the period closing market price are excluded.

Phantom Units. In January 2014, the Partnership awarded 668,074 phantom units to senior management and certain key employees. These awards are service condition (time-based) grants that vest 60% at the end of the third year of service and 40% at the end of the fifth year of service.

During 2013, the Partnership awarded 62,360 phantom units to senior management and certain key employees. These awards are service condition (time-based) grants that generally vest 60% at the end of the third year of service and 40% at the end of the fifth year of service. Distributions on the phantom units will be paid concurrent with the Partnership's distribution for common units.

In December 2012, the Partnership awarded 495,375 phantom units to senior management and certain key employees. These awards are service condition (time-based) grants that vest 60% at the end of the third year of service and 40% at the end of the fifth year of service. Also during 2012, 8,250 phantom units were awarded to senior management and key employees as service condition (time-based) grants that generally vest ratably over the next 5 years. Distributions on the phantom units (including non-vested units) will be paid concurrent with the Partnership's distribution for common units.

During 2011, the Partnership awarded 596,320 phantom units to senior management and certain key employees. These awards are service condition (time-based) grants that generally vest ratably over the next 5 years. Distributions on the phantom units (including non-vested units) will be paid concurrent with the Partnership's distribution for common units.

The following table presents phantom unit activity for the years ended December 31, 2013, 2012 and 2011:

2013

Phantom Units	Units	Weighted Average Grant Date Fair Value
Outstanding at the beginning of the period	1,231,342	$ 23.22
Service condition grants	62,360	25.44
Vested service condition	(231,163)	24.80
Forfeited service condition	(35,900)	23.22
Forfeited market condition	(44,397)	19.52
Total outstanding at end of period	982,242	23.16

2012

Phantom Units	Units	Weighted Average Grant Date Fair Value
Outstanding at the beginning of the period	1,086,393	$ 24.51
Service condition grants	503,625	21.39
Vested service condition	(223,258)	24.71
Vested market condition	(10,200)	19.52
Forfeited service condition	(120,868)	24.85
Forfeited market condition	(4,350)	19.52
Total outstanding at end of period	1,231,342	23.22

2011

Phantom Units	Units	Weighted Average Grant Date Fair Value
Outstanding at the beginning of the period	742,517	$ 23.61
Service condition grants	596,320	24.55
Vested service condition	(142,520)	24.73
Vested market condition	(8,550)	19.52
Forfeited service condition	(88,474)	24.99
Forfeited market condition	(12,900)	19.52
Total outstanding at end of period	1,086,393	24.51

The Partnership expects to recognize $19 million of unit-based compensation expense related to non-vested phantom units over a period of 3.3 years.

Exhibit 12.1

ENERGY TRANSFER EQUITY, L.P.

Computation of Ratio of Earnings to Fixed Charges

(in millions, except for ratio amounts)

(Unaudited)

	Years Ended December 31,				
	2013	2012	2011	2010	2009
Fixed charges:					
Interest expense	$ 1,221	$ 1,018	$ 740	$ 625	$ 468
Capitalized interest	45	101	14	29	16
Interest expense included in rental expense	16	6	3	3	3
Distribution to the Series A Convertible Redeemable Preferred Units	6	8	8	4	—
Accretion of the Series A Convertible Redeemable Preferred Units	—	1	—	—	—
Total fixed charges	1,288	1,134	765	661	487
Earnings:					
Income from continuing operations before income taxes	375	1,437	548	358	701
Less: equity in earnings (losses) of affiliates	236	212	117	65	20
Total earnings	139	1,225	431	293	681
Add:					
Fixed charges	1,288	1,134	765	661	487
Amortization of capitalized interest	7	5	4	3	1
Distributed income of equity investees	313	208	117	65	—
Less:					
Interest capitalized	(45)	(101)	(14)	(29)	(16)
Income available for fixed charges	$ 1,702	$ 2,471	$ 1,303	$ 993	$ 1,153
Ratio of earnings to fixed charges	1.32	2.18	1.70	1.50	2.37

Exhibit 21.1

LIST OF SUBSIDIARIES

SUBSIDIARIES OF ENERGY TRANSFER EQUITY, L.P., a Delaware limited partnership:

Eastern Gulf Crude Access, LLC, a Delaware limited liability company
Energy Transfer Crude Oil Company, LLC
Energy Transfer LNG Export, LLC
Energy Transfer Partners GP, L.P., a Delaware limited partnership
Energy Transfer Partners, L.L.C., a Delaware limited liability company
Energy Transfer Partners, L.P., a Delaware limited partnership
ETE Common Holdings Member, LLC, a Delaware limited liability company
ETE Common Holdings, LLC, a Delaware limited liability company
ETE GP Acquirer LLC, a Delaware limited liability company
ETE Services Company, LLC, a Delaware limited liability company
ETE Sigma Holdco, LLC, a Delaware limited liability company
Regency Employees Management Holdings LLC, a Delaware limited liability company
Regency Employees Management LLC, a Delaware limited liability company
Regency Energy Partners LP, a Delaware limited partnership
Regency GP LLC, a Delaware limited liability company
Regency GP LP, a Delaware limited partnership
Sunoco Partners LLC, a Pennsylvania limited liability company
Sunoco Partners Lease Acquisition & Marketing LLC, a Delaware limited liability company
Trunkline LNG Export, LLC

SUBSIDIARIES OF ENERGY TRANSFER PARTNERS, L.P., a Delaware limited partnership:

CCE Acquisition LLC, a Delaware limited liability company
CCE Holdings, LLC, a Delaware limited liability company
Chalkley Gathering Company, LLC, a Texas limited liability company
Citrus Corp., a Delaware corporation
Citrus Energy Services, Inc., a Delaware corporation
Citrus ETP Finance LLC, a Delaware limited liability company
CrossCountry Alaska, LLC, a Delaware limited liability company
CrossCountry Citrus, LLC, a Delaware limited liability company
CrossCountry Energy, LLC, a Delaware limited liability company
Eastern Gulf Crude Access, LLC, a Delaware limited liability company
Energy Transfer Crude Oil Company, LLC, a Delaware limited liability company
Energy Transfer Data Center, LLC, a Delaware limited liability company
Energy Transfer Dutch Holdings, LLC, a Delaware limited liability company
Energy Transfer Employee Management Company, a Delaware corporation
Energy Transfer Fuel GP, LLC, a Delaware limited liability company
Energy Transfer Fuel, LP, a Delaware limited partnership
Energy Transfer Group, LLC, a Texas limited liability company
Energy Transfer International Holdings LLC, a Delaware limited liability company
Energy Transfer Interstate Holdings, LLC, a Delaware limited liability company
Energy Transfer LNG Export, LLC, a Delaware limited liability company
Energy Transfer Mexicana, LLC, a Delaware limited liability company
Energy Transfer Peru LLC, a Delaware limited liability company
Energy Transfer Retail Power, LLC, a Delaware limited liability company
Energy Transfer Technologies, Ltd., a Texas limited partnership
Enhanced Service Systems, Inc., a Delaware corporation
ET Company I, Ltd., a Texas limited partnership
ET Fuel Pipeline, L.P., a Delaware limited partnership
ETC Compression, LLC, a Delaware limited liability company
ETC Endure Energy L.L.C., a Delaware limited liability company
ETC Energy Transfer, LLC, a Delaware limited liability company

ETC Fayetteville Express Pipeline, LLC, a Delaware limited liability company
ETC Fayetteville Operating Company, LLC, a Delaware limited liability company
ETC Gas Company, Ltd., a Texas limited partnership
ETC Gathering, LLC, a Texas limited liability company
ETC Hydrocarbons, LLC, a Texas limited liability company
ETC Interstate Procurement Company, LLC, a Delaware limited liability company
ETC Intrastate Procurement Company, LLC, a Delaware limited liability company
ETC Katy Pipeline, Ltd., a Texas limited partnership
ETC Lion Pipeline, LLC, a Delaware limited liability company
ETC M-A Acquisition LLC, a Delaware limited liability company
ETC Marketing, Ltd., a Texas limited partnership
ETC Midcontinent Express Pipeline, L.L.C., a Delaware limited liability company
ETC New Mexico Pipeline, L.P., a New Mexico limited partnership
ETC NGL Marketing, LLC, a Texas limited liability company
ETC NGL Transport, LLC, a Texas limited liability company
ETC Northeast Pipeline, LLC, a Delaware limited liability company
ETC Oasis GP, LLC a Texas limited liability company
ETC Oasis, L.P., a Delaware limited partnership
ETC ProLiance Energy, LLC, an Indiana limited liability company
ETC Texas Pipeline, Ltd., a Texas limited partnership
ETC Tiger Pipeline, LLC, a Delaware limited liability company
ETC Water Solutions, LLC, a Delaware limited liability company
ETE Holdco Corporation, a Delaware corporation
ETP Holdco Corporation, a Delaware corporation
ETP Newco 1 LLC, a Delaware limited liability company
ETP Newco 2 LLC, a Delaware limited liability company
ETP Newco 3 LLC, a Delaware limited liability company
ETP Newco 4 LLC, a Delaware limited liability company
ETP Newco 5 LLC, a Delaware limited liability company
Fayetteville Express Pipeline, LLC, a Delaware limited liability company
FEP Arkansas Pipeline, LLC, an Arkansas limited liability company
Five Dawaco, LLC, a Texas limited liability company
Florida Gas Transmission Company, LLC, a Delaware limited liability company
Heritage ETC GP, L.L.C., a Delaware limited liability company
Heritage ETC, L.P., a Delaware limited partnership
Heritage Holdings, Inc., a Delaware corporation
Houston Pipe Line Company LP, a Delaware limited partnership
HP Houston Holdings, L.P., a Delaware limited partnership
HPL Asset Holdings LP, a Delaware limited partnership
HPL Consolidation LP, a Delaware limited partnership
HPL GP, LLC, a Delaware limited liability company
HPL Holdings GP, L.L.C., a Delaware limited liability company
HPL Houston Pipe Line Company, LLC, a Delaware limited liability company
HPL Leaseco LP, a Delaware limited partnership
HPL Resources Company LP, a Delaware limited partnership
HPL Storage GP LLC, a Delaware limited liability company
LA GP, LLC, a Texas limited liability company
La Grange Acquisition, L.P., a Texas limited partnership
Lake Charles Exports, LLC, a Delaware limited liability company
Lake Charles LNG Exports, LLC, a Delaware limited liability company
Leapartners, L.P., a Texas limited partnership
Lee 8 Storage Partnership, a Delaware limited partnership
LG PL, LLC, a Texas limited liability company
LGM, LLC, a Texas limited liability company
Liberty Pipeline Group, LLC, a Delaware limited liability company
Lone Star NGL LLC, a Delaware limited liability company
Lone Star NGL Asset Holdings LLC, a Delaware limited liability company
Lone Star NGL Asset Holdings II LLC, a Delaware limited liability company

Lone Star NGL Asset GP LLC, a Delaware limited liability company
Lone Star NGL Development LP, a Delaware limited partnership
Lone Star NGL Pipeline LP, a Delaware limited partnership
Lone Star NGL Product Services LLC, a Delaware limited liability company
Lone Star NGL Hattiesburg LLC, a Delaware limited liability company
Lone Star NGL Mont Belvieu GP LLC, a Delaware limited liability company
Lone Star NGL Mont Belvieu LP, a Delaware limited partnership
Lone Star NGL Hastings LLC, a Delaware limited liability company
Lone Star NGL Refinery Services LLC, a Delaware limited liability company
Lone Star NGL Sea Robin LLC, a Delaware limited liability company
Lone Star NGL Fractionators LLC, a Delaware limited liability company
Lone Star NGL Marketing LLC, a Delaware limited liability company
MACS Retail LLC, a Virginia limited liability company
Mid-Atlantic Convenience Stores, LLC, a Delaware limited liability company
Oasis Partner Company, a Delaware corporation
Oasis Pipe Line Company Texas L.P., a Texas limited partnership
Oasis Pipe Line Company, a Delaware corporation
Oasis Pipe Line Finance Company, a Delaware corporation
Oasis Pipe Line Management Company, a Delaware corporation
Oasis Pipeline, LP, a Texas limited partnership
Pan Gas Storage LLC , a Delaware limited liability company
Panhandle Eastern Pipe Line Company, LP, a Delaware limited partnership
Panhandle Energy LNG Services, LLC, a Delaware limited liability company
Panhandle Holdings LLC, a Delaware limited liability company
Panhandle Storage LLC, a Delaware limited liability company
PEI Power Corporation, a Pennsylvania corporation
PEI Power II, LLC, a Pennsylvania corporation
PG Energy, Inc., a Pennsylvania corporation
Rich Eagleford Mainline, LLC, a Delaware limited liability company
Sea Robin Pipeline Company, LLC , a Delaware limited liability company
SEC Energy Products & Services, L.P., a Texas limited partnership
SEC Energy Realty GP, LLC, a Texas limited liability company
SEC General Holdings, LLC, a Texas limited liability company
SEC-EP Realty Ltd., a Texas limited partnership
Southern Union Gas Company, Inc., a Texas corporation
Southern Union Panhandle LLC, a Delaware limited liability company
Southside Oil, LLC, a Virginia limited liability company
SU Gas Services Operating Company, Inc., a Delaware corporation
SU Holding Company, Inc., a Delaware corporation
SU Pipeline Management LP, a Delaware limited partnership
SUCo LLC, a Delaware limited liability company
SUCo LP, a Delaware limited partnership
SUGAir Aviation Company, a Delaware corporation
SUG Holdings, LLC , a Delaware limited liability company
Sunoco Logistic Partners L.P. , a Delaware limited partnership
Sunoco Inc., a Pennsylvania corporation
Sunoco Partners LLC, a Pennsylvania limited liability company
TETC, LLC, a Texas limited liability company
Texas Energy Transfer Company, Ltd., a Texas limited partnership
Texas Energy Transfer Power, LLC, a Texas limited liability company
Transwestern Pipeline Company, LLC, a Delaware limited liability company
Trunkline Deepwater Pipeline LLC, a Delaware limited liability company
Trunkline Field Services LLC, a Delaware limited liability company
Trunkline Gas Company, LLC, a Delaware limited liability company
Trunkline LNG Company, LLC, a Delaware limited liability company
Trunkline LNG Export, LLC , a Delaware limited liability company
Trunkline LNG Holdings LLC, a Delaware limited liability company
Trunkline Offshore Pipeline LLC, a Delaware limited liability company

Whiskey Bay Gas Company, Ltd., a Texas limited partnership

Whiskey Bay Gathering Company, LLC, a Delaware limited liability company

SUBSIDIARIES OF REGENCY ENERGY PARTNERS LP, a Delaware limited partnership:

Regency OLP GP LLC, a Delaware limited liability company
Regency Energy Finance Corp., a Delaware corporation
Regency Gas Services LP, a Delaware limited partnership
Regency Field Services LLC, a Delaware limited liability company
Edwards Lime Gathering, LLC, a Delaware limited liability company
Regency Liquids Pipeline LLC, a Delaware limited liability company
Gulf States Transmission LLC, a Louisiana limited liability company
Regency Gas Utility LLC, a Delaware limited liability company
Pueblo Holdings, Inc., a Delaware corporation
Pueblo Midstream Gas Corporation, a Texas corporation
CDM Resource Management LLC, a Delaware limited liability company
FrontStreet Hugoton LLC, a Delaware limited liability company
WGP-KHC, LLC, a Delaware limited liability company
Regency Haynesville Intrastate Gas LLC, a Delaware limited liability company
RIGS Haynesville Partnership Co., a Delaware partnership
RIGS GP LLC, a Delaware limited liability company
Regency Intrastate Gas LP, a Delaware limited partnership
Regency Midcontinent Express LLC, a Delaware limited liability company
Midcontinent Express Pipeline LLC, a Delaware limited liability company
Regency Texas Pipeline LLC, a Delaware limited liability company
Lone Star NGL LLC, a Delaware limited liability company
Regency Ranch JV LLC, a Delaware limited liability company
Ranch Westex JV LLC, a Delaware limited liability company
ELG Oil LLC, a Delaware limited liability company
ELG Utility LLC, a Delaware limited liability company
RGU West LLC, a Texas limited liability company
RGP Westex Gatering Inc., a Texas corporation
RGP Marketing LLC, a Texas limited liability company
RHEP Crude LLC, a Texas limited liability company
West Texas Gathering Company, a Delaware corporation

SUBSIDIARIES OF SUNOCO, INC., a Pennsylvania corporation

Atlantic Petroleum (Out) LLC, a Delaware limited liability company

Atlantic Petroleum Corporation, a Delaware corporation

Atlantic Petroleum Delaware Corporation , a Delaware corporation

Atlantic Pipeline (Out) L.P. Texas limited partnership

Atlantic Refining & Marketing Corp., a Delaware corporation

Aventine Renewable Energy Holdings, Inc., a Delaware corporation

Clean Air Action Corporation, a Delaware corporation

Evergreen Assurance, LLC, a Delaware limited liability company

Evergreen Capital Holdings, LLC, a Delaware limited liability company

Evergreen Resources Group, LLC, a Delaware limited liability company

Helios Assurance Company, a Limited Bermuda other

Jalisco Corporation, a California corporation

Japan Sun Oil Company, Ltd., a Japan other

Lavan Petroleum Company (LAPCO), an Iran, Islamic Republic of other

Lesley Corporation, a Delaware corporation

Libre Insurance Company, Ltd., a Bermuda other

Lugrasa, S.A., a Panama corporation

Mascot, Inc. (MA), a Massachusetts corporation

Mid-Continent Pipe Line (Out) LLC, a Texas limited liability company

Oil Casualty Insurance, Ltd., a Bermuda other

Oil Insurance Limited, Bermuda limited company

Pacesetter/MVHC, Inc., a Texas corporation
PES Holdings, LLC, a Delaware limited liability company
Philadelphia Energy Solutions LLC, a Delaware limited liability company
Philadelphia Energy Solutions Refining and Marketing LLC, a Delaware limited liability company
Puerto Rico Sun Oil Company LLC, a Delaware limited liability company
Sun Alternate Energy Corporation, a Delaware corporation
Sun Atlantic Refining and Marketing B.V., a Netherlands other
Sun Atlantic Refining and Marketing B.V., Inc., a Delaware corporation
Sun Atlantic Refining and Marketing Company, a Delaware corporation
Sun Canada, Inc., a Delaware corporation
Sun Company, Inc., a Delaware corporation
Sun Company, Inc., a Pennsylvania corporation
Sun International Limited, a Bermuda other
Sun Lubricants and Specialty Products Inc., a Quebec corporation
Sun Mexico One, Inc., a Delaware corporation
Sun Mexico Two, Inc., a Delaware corporation
Sun Oil Company, a Delaware corporation
Sun Oil Export Company, a Delaware corporation
Sun Oil International, Inc., a Delaware corporation
Sun Petrochemicals, Inc., a Delaware corporation
Sun Pipe Line Company, a Texas corporation
Sun Pipe Line Delaware (Out) LLC, a Delaware limited liability company
Sun Refining and Marketing Company, a Delaware corporation
Sun Services Corporation, a Pennsylvania corporation
Sun Transport, LLC, a Pennsylvania limited liability company
Sun-Del Pipeline LLC, a Delaware limited liability company
Sun-Del Services, Inc., a Delaware corporation
Sunmarks, LLC, a Delaware limited liability company
Sunoco de Mexico, S.A. de C.V., a Mexico other
Sunoco Overseas, Inc., a Delaware corporation
Sunoco Power Marketing L.L.C., a Pennsylvania limited liability company
Sunoco Receivables Corporation, Inc., a Delaware corporation
Sunoco, Inc. (R&M), a Pennsylvania corporation
Sunoco, LLC, a Delaware limited liability company
The New Claymont Investment Company, a Delaware corporation
The Sunoco Foundation, a Pennsylvania not-for-profit corporation
Venezoil, C.A., a Venezuela other

SUBSIDIARIES OF SUNOCO LOGISTICS PARTNERS L.P., a Delaware limited partnership

Excel Pipeline LLC, a Delaware limited liability company
Inland Corporation, an Ohio corporation
Mid-Valley Pipeline Company, an Ohio corporation
Sun Pipe Line Company of Delaware LLC, a Delaware limited liability company
Sunoco Lease Acquisition & Marketing LLC, a Delaware limited liability company
Sunoco Logistics Partners GP LLC, a Delaware limited liability company
Sunoco Logistics Partners L.P., a Delaware limited partnership
Sunoco Logistics Partners Operations GP LLC, a Delaware limited liability company
Sunoco Logistics Partners Operations L.P., a Delaware limited partnership
Sunoco Partners Marketing & Terminals L.P., a Texas limited partnership
Sunoco Partners NGL Facilities LLC, a Delaware limited liability company
Sunoco Partners Operating LLC, a Delaware limited liability company
Sunoco Partners Real Estate Acquisition LLC, a Delaware limited liability company
Sunoco Partners Rockies LLC, a Delaware limited liability company
Sunoco Pipeline Acquisition LLC, a Delaware limited liability company
Sunoco Pipeline L.P., a Texas limited partnership
West Texas Gulf Pipe Line Company, a Delaware corporation

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our reports dated February 27, 2014, with respect to the consolidated financial statements and internal control over financial reporting of Energy Transfer Equity, L.P. included in the Annual Report of Energy Transfer Equity, L.P. on Form 10-K for the year ended December 31, 2013. We hereby consent to the incorporation by reference of said reports in the Registration Statements of Energy Transfer Equity, L.P. on Forms S-3 (File No. 333-192327 and File No. 333-146300) and on Form S-8 (File No. 333-146298).

/s/ GRANT THORNTON LLP

Dallas, Texas
February 27, 2014

EX 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our report dated February 27, 2014, with respect to the financial statements of ETE Common Holdings, LLC included in the Annual Report of Energy Transfer Equity, L.P. on Form 10-K for the year ended December 31, 2013. We hereby consent to the incorporation by reference of said report in the Registration Statements of Energy Transfer Equity, L.P. on Forms S-3 (File No. 333-192327 and File No. 333-146300) and on Form S-8 (File No. 333-146298).

/s/ GRANT THORNTON LLP

Dallas, Texas
February 27, 2014

Exhibit 23.3

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our report dated February 27, 2014, with respect to the consolidated financial statements of Energy Transfer Partners, L.P. included in the Annual Report of Energy Transfer Equity, L.P. on Form 10-K for the year ended December 31, 2013. We hereby consent to the incorporation by reference of said report in the Registration Statements of Energy Transfer Equity, L.P. on Forms S-3 (File No. 333-192327 and File No. 333-146300) and on Form S-8 (File No. 333-146298).

/s/ GRANT THORNTON LLP

Dallas, Texas
February 27, 2014

EX 23.4

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our report dated February 27, 2014, with respect to the consolidated financial statements of Energy Transfer Partners GP, L.P. included in the Annual Report of Energy Transfer Equity, L.P. on Form 10-K for the year ended December 31, 2013. We hereby consent to the incorporation by reference of said report in the Registration Statements of Energy Transfer Equity, L.P. on Forms S-3 (File No. 333-192327 and File No. 333-146300) and on Form S-8 (File No. 333-146298).

/s/ GRANT THORNTON LLP

Dallas, Texas
February 27, 2014

Exhibit 23.5

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our report dated February 27, 2014, with respect to the consolidated financial statements of Regency Energy Partners LP included in the Annual Report of Energy Transfer Equity, L.P. on Form 10-K for the year ended December 31, 2013. We hereby consent to the incorporation by reference of said report in the Registration Statements of Energy Transfer Equity, L.P. on Forms S-3 (File No. 333-192327 and File No. 333-146300) and on Form S-8 (File No. 333-146298).

/s/ GRANT THORNTON LLP

Dallas, Texas
February 27, 2014

EX 23.6

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our report dated February 27, 2014, with respect to the consolidated financial statements of Regency GP LP included in the Annual Report of Energy Transfer Equity, L.P. on Form 10-K for the year ended December 31, 2013. We hereby consent to the incorporation by reference of said report in the Registration Statements of Energy Transfer Equity, L.P. on Forms S-3 (File No. 333-192327 and File No. 333-146300) and on Form S-8 (File No. 333-146298).

/s/ GRANT THORNTON LLP

Dallas, Texas
February 27, 2014

EX 23.7

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our report dated February 27, 2014, with respect to the consolidated financial statements of ETE GP Acquirer LLC included in the Annual Report of Energy Transfer Equity, L.P. on Form 10-K for the year ended December 31, 2013. We hereby consent to the incorporation by reference of said report in the Registration Statements of Energy Transfer Equity, L.P. on Forms S-3 (File No. 333-192327 and File No. 333-146300) and on Form S-8 (File No. 333-146298).

/s/ GRANT THORNTON LLP

Dallas, Texas
February 27, 2014

Exhibit 23.8

CONSENT OF INDEPENDENT CERTIFIED PUBLIC ACCOUNTANTS

We have issued our report dated February 27, 2014, with respect to the consolidated financial statements of RIGS Haynesville Partnership Co. incorporated by reference in the Annual Report of Energy Transfer Equity, L.P. on Form 10-K for the year ended December 31, 2013. We hereby consent to the incorporation by reference of said report in the Registration Statements of Energy Transfer Equity, L.P. on Forms S-3 (File No. 333-192327 and File No. 333-146300) and on Form S-8 (File No. 333-146298).

/s/ GRANT THORNTON LLP

Dallas, Texas
February 27, 2014

Exhibit 23.9

CONSENT OF INDEPENDENT CERTIFIED PUBLIC ACCOUNTANTS

We have issued our report dated February 27, 2014, with respect to the consolidated financial statements of Lone Star NGL LLC incorporated by reference in the Annual Report of Energy Transfer Equity, L.P. on Form 10-K for the year ended December 31, 2013. We hereby consent to the incorporation by reference of said report in the Registration Statements of Energy Transfer Equity, L.P. on Forms S-3 (File No. 333-192327 and File No. 333-146300) and on Form S-8 (File No. 333-146298).

/s/ GRANT THORNTON LLP

Dallas, Texas
February 27, 2014

Exhibit 23.10

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the following Registration Statements:

(1) Registration Statement on Form S-3 No. 333-192327 of Energy Transfer Equity, L.P.
(2) Registration Statement on Form S-3 No. 333-146300 of Energy Transfer Equity, L.P.
(3) Registration Statement on Form S-8 No. 333-146298 pertaining to the Employees' Savings Plan of Energy Transfer Equity, L.P.

of our report dated March 1, 2013, with respect to the consolidated financial statements of Sunoco Logistics Partners L.P., included in this Annual Report (Form 10-K) of Energy Transfer Equity, L.P. for the year ended December 31, 2013.

/s/Ernst & Young LLP

Philadelphia, Pennsylvania
February 27, 2014

Exhibit 23.11

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-146300), on Form S-3 ASR (No. 333-192327) and on Form S-8 (No. 333-146298) of Energy Transfer Equity, L.P of our reports dated February 21, 2014 and February 19, 2013 relating to the financial statements of Midcontinent Express Pipeline LLC, which appear in Exhibits 99.3 and 99.4 of the 2013 Annual Report on Form 10-K of Regency Energy Partners LP, which is incorporated in this Annual Report on Form 10-K.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 27, 2014

Exhibit 31.1

CERTIFICATION OF PRESIDENT (PRINCIPAL EXECUTIVE OFFICER)
PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, John W. McReynolds, certify that:

1. I have reviewed this annual report on Form 10-K of Energy Transfer Equity, L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. I am responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under my supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to me by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under my supervision, 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;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report my conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. I have disclosed, based on my most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize, and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 27, 2014

/s/ John W. McReynolds

John W. McReynolds
President

Exhibit 31.2

**CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002**

I, Jamie Welch, certify that:

1. I have reviewed this quarterly report on Form 10-K of Energy Transfer Equity, L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. I am responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under my supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to me by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under my supervision, 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;

   c. Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report my conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. I have disclosed, based on my most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: February 27, 2014

/s/ Jamie Welch

Jamie Welch
Chief Financial Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the annual report of Energy Transfer Equity, L.P. (the "Partnership") on Form 10-K for the year ended December 31, 2013, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, John W. McReynolds, President, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Date: February 27, 2014

/s/ John W. McReynolds
John W. McReynolds
President

A signed original of this written statement required by Section 906 has been provided to and will be retained by Energy Transfer Equity, L.P. and furnished to the Securities and Exchange Commission upon request.

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the quarterly report of Energy Transfer Equity, L.P. (the "Partnership") on Form 10-K for the year ended December 31, 2013, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Jamie Welch, Chief Financial Officer, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Date: February 27, 2014

/s/ Jamie Welch

Jamie Welch
Chief Financial Officer

A signed original of this written statement required by Section 906 has been provided to and will be retained by Energy Transfer Equity, L.P. and furnished to the Securities and Exchange Commission upon request.

Exhibit 99.1

REPORT OF ERNST & YOUNG LLP, INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON FINANCIAL STATEMENTS

To the Board of Directors of
Sunoco Partners LLC and Limited Partners of Sunoco Logistics Partners L.P.

We have audited the accompanying consolidated balance sheets of Sunoco Logistics Partners L.P. (the "Partnership") as of December 31, 2012 (successor), and the related consolidated statements of comprehensive income, equity, and cash flows for the period from October 5, 2012 to December 31, 2012 (successor), the period from January 1, 2012 to October 4, 2012 (predecessor) and the year ended December 31, 2011 (predecessor). These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Sunoco Logistics Partners L.P. at December 31, 2012 (successor) and the consolidated results of its operations and its cash flows for the period from October 5, 2012 to December 31, 2012 (successor), the period from January 1, 2012 to October 4, 2012 (predecessor) and the year ended December 31, 2011 (predecessor), in conformity with U.S. generally accepted accounting principles.

/s/ Ernst & Young LLP

Philadelphia, Pennsylvania
March 1, 2013